BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 307

In the Matter of PACIFICORP, dba PACIFIC POWER, 2017 Transition Adjustment Mechanism.	ORDER

DISPOSITION: NET POWER COSTS APPROVED SUBJECT TO ADJUSTMENT

I. INTRODUCTION

In Order No. 16-418, we granted PacifiCorp, dba Pacific Power's request to update its 2017 net power costs (NPC) in a preliminary order, subject to the company's final NPC update. In this order, we describe more fully the parties' positions and the rationale for our decisions in that order.

We also direct PacifiCorp to delay filing of its long-term fuel supply plan for the Jim Bridger coal units.[1] Instead, we direct PacifiCorp, Staff, and the parties to informally meet and discuss (1) the information and analyses needed to meaningfully evaluate PacifiCorp's long-term fuel supply plan for the Jim Bridger coal units in future Transition Adjustment Mechanism (TAM) proceedings, as well as (2) whether additional information and analyses should be provided to Staff and the parties regarding PacifiCorp's fuel plans for any of its other coal-fired units. We direct Staff to report back to us on the results of those discussions, with any recommendations, at the January 24, 2017 Public Meeting.

We also direct PacifiCorp, Staff, and parties to participate in workshops to examine the following GRID issues: (1) Day-Ahead/Real-Time Transaction (DART) adjustments,

[1] In Order No. 13-387, we directed PacifiCorp to prepare a periodic fuel supply plan that compares affiliate mine fuel supply to other alternative fuel supply options, including market alternatives, to facilitate implementing prudence and affiliate transaction standards in future rate proceedings. PacifiCorp made two filings in its 2015 TAM in docket UE 287: first, as part of its initial filing, PAC/201 described the process it would use to prepare plans for Jim Bridger; second, as a compliance to our order approving the 2015 TAM. PacifiCorp filed the long-term fuel supply plan on December 30, 2015.

(2) Energy Imbalance Market (EIM) benefit estimation, and (3) Renewable Energy Credit (REC) valuation.

With respect to the first two issues, our intent is for PacifiCorp to describe its modeling approach in detail during the workshops to facilitate the parties' deeper understanding of these issues. We expect parties challenging PacifiCorp's modeling choices to engage in these discussions in order to fully understand the rationale behind the adjustments. Our goal is to create an improved evidentiary record on these disputed issues going forward. While the workshops are intended to be informational in nature, parties may also use the workshops to discuss whether any adjustments to PacifiCorp's existing methodologies may be appropriate. With respect to the REC issue, the parties should discuss whether there is a reasonable method to value RECs based on delaying the time when PacifiCorp is required to take any substantive action to ensure RPS compliance, as discussed later in this order. Staff is to report back to us on the results of these workshops before PacifiCorp's 2018 TAM is filed.[2]

In addition, to help the Commission and the parties to more fully understand PacifiCorp's direct access opt-out charge during the next TAM proceeding, we direct PacifiCorp to provide a historical time series of fixed generation costs broken down by its components (e.g., capital, O&M) as a check on the reasonableness of its forecasts. PacifiCorp should include this information in its next TAM filing.

As a result of our decisions, PacifiCorp's final compliance filing for its 2017 NPC shows Oregon allocated costs of $350.2 million. This translates to an overall annual revenue increase of $11.7 million or approximately 0.9 percent. PacifiCorp's indicative update removed the cost of avian curtailments, as directed by our preliminary order, and also moved all production tax credits from base rates to NPC, as agreed to by Staff and the company.[3] The final update filing shows 2017 power costs of $25.36 MWh.

II. BACKGROUND

PacifiCorp's TAM is an annual filing in which PacifiCorp projects the amount of power costs to be reflected in customer rates for the following year, as well as to set transition charges for customers electing to move to direct access. The TAM effectively removes regulatory lag for the company because the forecasts are used to adjust rates. For that reason, the accuracy of the

[2] We do not seek recommendations from Staff based on this set of informational workshops but simply a report on the parties' discussions.

[3] As authorized by Section 18(b) of SB 1547, PacifiCorp's initial filing contained a $5.0 million revenue requirement increase to account for expiring PTCs at several company-owned facilities. To allow the PTCs to be more easily updated in future TAM filings, Staff and PacifiCorp subsequently agreed to account for the PTC variance by removing PTCs from Schedule 200—a rate that reflects the company's fixed generation costs that was last set in the 2014 rate case in docket UE 263—and instead include the 2017 PTCs in the TAM NPC, Schedule 201.

forecasts is of significant importance to setting fair just and reasonable rates. Our goal, therefore, is to achieve an accurate forecast of PacifiCorp's power costs for the upcoming year.

PacifiCorp projects its NPC using an optimized production cost model called Generation and Regulation Initiatives Decision Tools (GRID), which simulates the operation of PacifiCorp's power system on an hourly basis. GRID receives inputs representing PacifiCorp's system, such as load, resources available to serve the load, and transmission constraints. The GRID model calculates the least-cost solution to balance PacifiCorp's load and resources each hour while meeting system reliability and operational constraints. In that sense, GRID is optimized for perfect efficiency while maintaining system reliability. The company makes adjustments to reflect real life operations to achieve a more realistic net power forecast.[4]

This year, PacifiCorp's reply update projected 2017 NPC on an Oregon-allocated basis of $375.5 million, $16.2 million higher than the 2016 TAM, for an overall average rate increase of 1.3 percent. PacifiCorp explains that its NPC has increased due to decreased wholesale sales revenue, increased qualifying facility (QF) costs, and a true-up of production tax credits (PTCs).

The Citizens' Utility Board of Oregon (CUB), the Industrial Customers of Northwest Utilities (ICNU), and Noble Americas Energy Solutions LLC (Noble Solutions) intervened in this proceeding, and Commission Staff also participated. All parties filed testimony and briefs. A hearing was held on August 29, 2016.

The parties request several adjustments to PacifiCorp's filing:

- Staff, ICNU, and CUB raise several coal related issues, including PacifiCorp's decision to use coal purchased from an affiliate to fuel the Jim Bridger plant, the company's minimum-take provisions in its coal contracts, and a coal plant dispatch modeling adjustment.

- Staff, CUB, and ICNU recommend rejection of PacifiCorp's system balancing adjustment DART, which increases the NPC forecast by $9.0 million on an Oregon-allocated basis.

- Staff and CUB contend that PacifiCorp has underestimated and improperly quantified EIM benefits of $4.41 million on an Oregon-allocated basis.

[4] Tr. Vol. I at 43-44 (Aug 29, 2016).

- Staff requests an adjustment of approximately $65,000 on an Oregon-allocated basis to remove from NPC the costs associated with lost energy from avian protection curtailments.

- Staff and CUB contend that PacifiCorp overestimates new QF contracts, thereby improperly increasing its NPC, and propose that the company discount new QF contracts by historical success factors.

- Noble Solutions asks that the transition adjustments include a credit for the value of RECs freed up by departing direct access customers, and also seeks an adjustment to the opt-out charge in the five-year program.

In reviewing the TAM, PacifiCorp has the burden of proof to show that its proposal is fair, just and reasonable.

III. DISCUSSION

A. Overview

In our preliminary order, we found that PacifiCorp justified its 2017 NPC with evidence in the record that was not adequately rebutted by the parties. In this order we explain why we decline all adjustments other than Staff's avian curtailment proposal.

We also explain our next steps with the TAM. As noted previously, we direct Staff to report back to us by the end of January 2017 on the results of discussions regarding PacifiCorp's coal fuel-supply plans, and before the next TAM on the results of workshop discussions regarding three GRID issues.

B. Coal Costs, Contracts, and Modeling

Staff, ICNU, and CUB challenged several aspects of the company's forecasted coal costs. First, Staff and ICNU challenge PacifiCorp's projected costs to fuel the Jim Bridger coal plant, each alleging that continued reliance on affiliated Bridger Coal Company (BCC) is more expensive than market alternatives. Staff recommends a prudence disallowance, asserting PacifiCorp did not fully consider market alternatives in its long-term planning. ICNU takes a different approach, invoking our lower-of-cost-or-market rule to request that we reprice BCC coal. Next, CUB challenges the prudence of several recent supply contracts that contain provisions committing PacifiCorp to minimum coal volumes. Finally, Staff objects to the way PacifiCorp manually adjusted GRID to account for these minimum-take provisions, deeming it a modeling change prohibited by the moratorium in last year's TAM.

1. Prudence of 2017 Fuel Strategy for Jim Bridger Coal Plant

In 2017, PacifiCorp projects it will continue to source fuel for the Jim Bridger plant mostly from BCC, which has provided "mine mouth" coal to the plant since 1974. In recent years, PacifiCorp has acquired two-thirds of the plant's fuel from the adjacent BCC mine and one-third from the Black Butte mine 20 miles away. For 2017, PacifiCorp projects sourcing 65 percent from BCC, 30 percent from Black Butte, and 5 percent from the Powder River Basin (PRB) mines 400 to 600 miles to the north.

PacifiCorp's most recent fueling plan, the "Long-Term Fuel Plan" filed with the Commission in 2015, targets a transition to greater reliance on PRB coal starting mid-2023. PacifiCorp estimates it will take up to six years to permit and construct the infrastructure necessary to receive and burn large volumes of PRB coal. For the plant to burn entirely PRB coal in 2017, PacifiCorp states, it would have had to change its fuel plan during 2013 at the latest, to begin an expedited conversion process in 2014.

a. Parties' Positions

Staff argues that the company's 2017 fuel strategy is not least-cost, least-risk. Staff maintains that, had PacifiCorp prudently undertaken a comprehensive long-term analysis in 2013, it would have discovered that lower-priced market options were viable, including coal from PRB mines. Instead, argues Staff, PacifiCorp engaged in short-term analysis and relied too heavily on an outdated figure for the cost of needed retrofits. Staff asks for a $23.5 million (Oregon allocated) disallowance to represent the amount customers would have saved in 2017 NPC by a switch to PRB coal in 2017.

PacifiCorp responds that in 2013, it made a prudent decision to sustain its historical BCC/Black Butte fueling strategy. This strategy was thoroughly vetted, PacifiCorp presses, through the course of successive TAM proceedings, including our finding in October 2013 in the 2014 TAM, that the proposed BCC/Black Butte fuel strategy was reasonable and prudent.[5] PacifiCorp maintains the prohibitively high estimate at the time from consultant Black and Veatch for the cost of needed retrofits consistently rendered PRB uneconomic compared to available alternatives.

Leading up to (and after) 2013, PacifiCorp maintains, it prepared a BCC mine plan with a 10-year planning horizon to develop a strategy for least-cost, least-risk fueling of the Jim Bridger plant. And every two years, it developed a more comprehensive life-of-plant fueling plan for the Integrated Resource Plan (IRP) (including the 2011, 2013, and 2015 IRPs) to assess and determine the least-cost, least-risk fueling option. These plans, PacifiCorp argues, included PRB

[5] *In the Matter of PacifiCorp, dba Pacific Power, 2014 Transition Adjustment Mechanism,* Docket No. UE 264, Order No. 13-387 (Oct 28, 2013).

as a potential source. Staff counters that the evaluations and analysis in these plans are fundamentally inadequate to support a finding that the company's strategy for the 2017 TAM is least-cost, least-risk.

After 2013, PacifiCorp attests, it continued to look at PRB coal in its long-term planning. In June 2014, it issued a Request for Proposals (RFP) for coal to serve the Jim Bridger plant, which it sent to suppliers including PRB mines. This resulted in the current Black Butte contract, which proved lower cost than PRB. And in July 2014, it completed a new long-term fuel plan for its 2015 IRP that reflected PRB as a long-term source for the plant. This plan, explains PacifiCorp, evolved into the Long-Term Fuel Plan filed with the Commission in 2015 that targets 2023 to start the transition to PRB coal. PacifiCorp describes this plan as a new tool that added to its existing planning.

PacifiCorp allows that BCC unit costs have increased relative to last year's TAM, but says this was driven by market changes in early 2016. By the reply update, PacifiCorp points out, market conditions had returned to a more normal state and forecasted BCC unit costs decreased as plant dispatch increased. PacifiCorp contends that Staff's long-term analysis favors PRB coal only because of errors and incorrect assumptions including Staff's "facially unreasonable" transportation charge, use of a 2015 figure for the cost of retrofits, and unreasonable amortization periods for the retrofits and plant.

PacifiCorp suggests rejecting Staff's adjustment and opening an expedited planning docket to consider the least-cost, least-risk fuel supply plan for the Jim Bridger plant.

b. Resolution

In a prudence review, we look at the objective reasonableness of a decision at the time it was made, considering the information then available to the utility.[6] We examine all actions of the utility—including the process that the utility used to make a decision.[7] We do not require perfection; just that the utility's actions were reasonable.[8]

Here, considering the evidence of what PacifiCorp knew or should have known in 2013, we conclude that PacifiCorp was reasonable in not accelerating conversion to PRB coal at that time. We approved the company's fuel strategy that same year in the 2014 TAM, finding BCC and Black Butte provided a reasonable, stable coal supply. PacifiCorp has demonstrated that it considered market alternatives to BCC coal before, during, and after 2013 in its various approaches to long-term planning for the plant, but consistently found the cost of conversion to

[6] *In the Matters of PacifiCorp*, Docket Nos. UM 995, UE 121, and UC 578, Order No. 02-469 at 4-5 (Jul 18, 2002).
[7] *In re PacifiCorp*, Docket No. UE 246, Order No. 12-493 at 26 (Dec 20, 2012).
[8] *In the Matter of Portland General Electric Company Application to Amortize the Boardman Deferral*, Docket No. UE 196, Order No. 10-051 at 11 (Feb 11, 2010).

PRB coal too costly. The estimate that PacifiCorp had at the time from consultant Black and Veatch for the cost of needed retrofits rendered PRB uneconomic compared to available alternatives.[9] We recognize that integrating PRB coal supply at the Jim Bridger plant is a complicated undertaking that will involve avoiding contractual commitments, closing the BCC mine, and solving operational challenges and would not expect the company to turn on a dime to make this irreversible conversion.

However, our inquiry does not end there, as we will revisit PacifiCorp's fueling decisions annually in the TAM. Staff and parties have stated a desire for additional information and analyses to more fully evaluate the long-term fuel supply plan for the Jim Bridger plant. Accordingly, we direct PacifiCorp to delay filing of its long-term fuel supply plan for the Jim Bridger coal units. Instead, we direct PacifiCorp, Staff, and the parties to informally meet and discuss: (1) the information and analyses needed to meaningfully evaluate PacifiCorp's long-term fuel supply plan for the Jim Bridger coal units in future TAM proceedings, as well as (2) whether additional information and analyses should be provided to Staff and the parties regarding PacifiCorp's fuel plans for any of its other coal-fired units. We direct Staff to report back to us on the results of those discussions, with any recommendations, at our January 24, 2016 Public Meeting.

2. *Application of Lower-of-Cost-or-Market Rule*

a. *Parties' Positions*

ICNU contends that we should apply our Lower-of-Cost-or-Market-Rule found in OAR 860-027-0028 to reduce the price of BCC coal in the company's forecasted 2017 NPC. The rule requires that services or supplies transferred or provided from an affiliate are recorded at the lower of the affiliate's cost or the market rate. "Market rate" is defined as the lowest price that is available from nonaffiliated suppliers for comparable services or supplies. ICNU claims that PRB coal is lower-cost than affiliated BCC coal for 2017, even after accounting for the needed retrofits and amortization of the undepreciated mine investment. ICNU recommends that we apply the rule here to reduce the forecasted costs related to BCC coal deliveries by $6 million (Oregon allocated).

ICNU proposed a similar adjustment in the 2014 TAM.[10] In that case, ICNU proposed to reprice BCC coal at the 2014 contract cost of Black Butte coal. PacifiCorp argued that sufficient additional volumes from Black Butte were not available because the mine did not have sufficient excess capacity, and even if it did, the price would be higher than the existing contract price. We

[9] The total estimated cost is provided in confidential PAC/1002, Ralston/6.
[10] Order No. 13-387 at 7.

rejected ICNU's adjustment, finding ICNU's use of the 2014 contract price as a substitute price to be unpersuasive.

In this proceeding, ICNU refines its adjustment and argues that what matters is not that the utility can literally substitute the market product but instead that the market price is a fair comparison. ICNU maintains we have never specifically found the rule requires the market alternative to be physically available to replace the affiliate supply. To find otherwise, ICNU cautions, could allow a utility to avoid application of the rule by deferring investments that would otherwise be in the best interest of customers.

Staff supports ICNU's adjustment, attesting that it and ICNU have presented comprehensive analysis that demonstrates PRB coal is a viable, lower-cost market alternative to BCC coal. Staff adds that we have consistently evaluated the reasonableness of BCC costs by comparing those costs to market alternatives.

PacifiCorp argues that, like ICNU's adjustment in the 2014 TAM, the market alternative here cannot actually replace BCC coal in 2017. Due to the retrofits needed to handle PRB coal, PacifiCorp explains, it is impossible for the company to rely on the volume of PRB coal that would be needed. The plain and ordinary meaning of "available," PacifiCorp argues, is *present, ready for immediate use, accessible, obtainable*. PacifiCorp insists that harm to customers can only occur if the utility could have reduced its costs but chose instead to rely on the affiliate supplier. Even if the Jim Bridger plant could physically accept PRB coal in 2017, PacifiCorp continues, it would not be lower cost. ICNU's pricing, PacifiCorp argues, unreasonably changes the amortization period from 4 years to 13 years and lowers the return on the company's undepreciated investment in the mine.

b. Resolution

Based on the evidence in the record, we are not persuaded that we should substitute a market rate for BCC pricing in 2017. At present, the PRB market rate that ICNU proposes is not actually available to PacifiCorp to fuel the Jim Bridger plant because the company has not yet retrofitted the plant to receive and burn high volumes of PRB coal. Consequently, this adjustment relies on the same issue as Staff's proposed adjustment—whether as of late 2013, a reasonable utility would have invested PacifiCorp's share of the investment required to make the switch to PRB coal in 2017. We find in this order that, considering the evidence in the record of what PacifiCorp knew or should have known in 2013, the company was reasonable in adhering to its historical fueling strategy. As a result, it would be inconsistent to hold PacifiCorp accountable for a market rate that would be available only if it had decided differently in 2013.

3. Prudence of Coal Supply Contracts with Minimum-Take Provisions

PacifiCorp's 2017 NPC include three coal supply contracts executed since PacifiCorp's 2013 IRP (i.e., 2015 and beyond). These comprise a coal supply agreement for the Jim Bridger plant that expires in 2017, a supply agreement for the Dave Johnston plant that expires in 2018, and long-term supply agreement for the Huntington plant. All of these contracts have a minimum-take, or "take-or-pay," provision that requires PacifiCorp to purchase a minimum specified amount of coal over a given time period.

a. Parties' Positions

CUB suggests it was imprudent for PacifiCorp to make this type of binding and ongoing commitment to minimum coal volumes given the uncertainty of federal, environmental, and regulatory constraints. CUB recommends disallowing all costs and impacts of the minimum-take provisions in these recent contracts. This would require that the GRID model be rerun with the minimum of either the market cost of coal or the contract price input as the incremental cost of coal.

Staff shares CUB's concern that the prudence of entering into contracts with take-or-pay provisions is questionable. Still, Staff believes there is not sufficient evidence on the record to address the prudence of these contracts and suggests delaying any determination until the company's 2017 power cost adjustment mechanism (PCAM) proceeding.

PacifiCorp responds that these provisions are a component of virtually all cost-effective coal supply agreements and constitute the consideration required to obtain favorable pricing. These guarantees provide investment security for the seller, PacifiCorp explains, ensuring steady revenue for continued investment in the resources necessary to supply coal. The alternative, PacifiCorp states, would be to rely on the spot market for coal, thus exposing customers to significant risk in supply reliability and price variability. PacifiCorp states it has never relied exclusively on the spot market and doing so would be categorically imprudent.

b. Resolution

We are not persuaded by CUB's claim that committing to coal supply agreements with these minimum-take provisions was imprudent by PacifiCorp. As PacifiCorp points out, two of these contracts are short-term, expiring in 2017 and 2018. Moreover, PacifiCorp provided evidence that these provisions are typical in coal supply agreements and that, without entering into supply agreements with these types of provisions, it would have to rely on the spot market with the attendant supply and price risk.

4. *Modeling of Minimum-Take Provisions in 2017 TAM*

When PacifiCorp prepared the initial filing for this TAM proceeding, market conditions were such that it had to manually adjust its GRID model to increase the dispatch of plants subject to minimum-take provisions. To do this, it manually adjusted the incremental cost of coal to achieve the overall least-cost dispatch of the entire coal fleet while meeting the minimum-take obligations for each plant. The GRID model does not innately account for this type of contract provision. By the time of the reply update, there was no longer a need to make this adjustment as higher wholesale electricity prices had naturally increased the forecasted dispatch of the affected plants.

a. *Parties' Positions*

Staff asserts that PacifiCorp's manual adjustment constituted a modeling change prohibited by the moratorium we imposed last year on changes in the 2017 cycle.[11] Staff argues that PacifiCorp has not demonstrated that parties were notified of this change in this proceeding or in previous TAMs. Staff recommends postponing this change for a year to allow Staff to fully analyze the 2016 TAM changes, consistent with the intent of the moratorium. For purposes of 2017 NPC, Staff proposes that fuel cost could be calculated at the marginal contract or spot price, resulting in a \$3.9 million (Oregon allocated) reduction.

PacifiCorp responds that its approach to modeling minimum-take provisions through manual adjustment to the incremental cost of coal is consistent with past TAM proceedings and has been part of the GRID model since 2005. The modeling predated the TAM Guidelines, it explains, and it did provide notice when it revised GRID in 2005. The effect was more pronounced this year, PacifiCorp explains, because the historically low-market prices for natural gas and electricity resulted in decreased coal plant dispatch in the initial filing. PacifiCorp points to specific plants for which it reduced the incremental contract costs in the 2015 and 2016 TAMs to increase the volume used by the plants beyond the minimum-take volume.

PacifiCorp also challenges the amount of Staff's adjustment. First, PacifiCorp suggests Staff quantified its adjustment based on the minimum-take provisions implicated in the initial filing, not the reply update, where the adjustment would now be zero. Second, PacifiCorp suggests that Staff double-counts the impact at the Jim Bridger plant because Staff separately included the same adjustment in its proposed disallowance for Jim Bridger coal supply.

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[11] *See In the Matter of PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 4 (Dec 11, 2015) (imposing moratorium on modeling changes in the 2017 cycle to provide time for Staff, parties, and Commissioners to better understand recent changes).

b. Resolution

We are not persuaded by Staff's argument that this is an improper modeling change. PacifiCorp has demonstrated that this practice is consistent with past TAM proceedings. The company cites specific plants for which it made these types of adjustments in past TAMs. The impact is more pronounced this year, it explains, because of low electricity market prices at the time it prepared its initial filing.

C. Day-Ahead Real-Time Balancing Transactions (DART Adjustment)

In the 2016 TAM, we approved PacifiCorp's system balancing transactions adjustment (DART adjustment).[12] The DART adjustment includes two components to capture system balancing costs that are neither included in the company's forward price curve nor modeled in GRID. Under this adjustment, PacifiCorp first increases the overall prices in GRID for forecasted system balancing sales and purchases to recognize that the company is a price-taker—that is, paying more in heavy load hours than average actual market prices, and selling for lower than average during light load hours ($5.4 million).[13] Second, the company increases the volumes of balancing transactions by 30 percent to account for the use of monthly, daily, and hourly products ($3.6 million).[14]

In approving this adjustment last year, we agreed that PacifiCorp's average balancing purchase prices systematically exceed its average balancing sales prices. We also found that GRID understated the volumes of balancing transactions. For these reasons, we approved the DART adjustment to improve forecast accuracy.

Staff, CUB, and ICNU contend the DART adjustment contains numerous flaws and recommend we reverse our decision. They propose we reject the DART adjustment now, and then allow the parties to work on an improved methodology. We summarize their arguments below.

1. Arbitrary Price Adders

Staff claims the price adder component of the DART adjustment is unrealistic and arbitrary. For example, Staff states the price adjustment is inflated by averaging the price difference over a monthly period, rather than a shorter, more accurate time period. Staff points out that the company has the ability to use a more granular time period because the prices in GRID are reshaped by day of the week and hour of the day to match historic patterns. PacifiCorp responds that the monthly time horizon matches the time periods used in the forward price curve.

[12] *Id.*.
[13] PAC/400, Dickman/21.
[14] PAC/100, Dickman/19; PAC/400, Dickman/22.

Staff also challenges the use of separate purchase and sale prices for each hour. Staff states that there is only a single clearing price in any given market at any one point in time, and that GRID already differentiates market price into periods of higher and lower prices. PacifiCorp responds that the use of two market prices is necessary because GRID is either buying or selling in each hour, and that the use of separate market prices gives GRID better signals. Staff disagrees and believes this misrepresents GRID, because PacifiCorp often makes purchases at one hub and sales at another hub. Staff explains that, with DART, PacifiCorp increases the price of the buying hub above forecast and decrease the price of the selling hub below forecast. Moreover, Staff emphasizes that PacifiCorp agrees with Staff, ICNU, and CUB that a single price, when properly correlated, would accomplish the objective of PacifiCorp's two-price system by representing market prices within GRID.

ICNU and CUB contend that the company should use the data it already has on production capacity and capacity factors to determine when the market prices that it will pay are above or below average. CUB states that the company has been uncooperative regarding alternative approaches to DART.

2. Unsupported Increases to Market Transaction Volumes

Staff asserts that PacifiCorp's volume component adjustment is arbitrary. Staff argues that adjustment uses historic market transactions inequitably by pushing historical costs into NPC without offsetting historical benefits such as variations in fuel price. PacifiCorp responds that it is properly using normalized historical results.

Staff states that the DART price adders eliminate the value of arbitrage transactions. Staff explains that arbitrage transactions should reduce NPC through the variance between purchase price at one hub and sale price at another hub, or the difference between hubs. Staff also distinguishes the arbitrage transactions that PacifiCorp includes, which are different because they capture the price difference between hub and market price (not hub to hub). PacifiCorp responds that the adjustment properly includes arbitrage transactions and excludes hedging transactions.

CUB argues that PacifiCorp's volume adjustment improperly uses pre-EIM data. PacifiCorp responds that EIM participation has not decreased the company's system balancing costs, because under the EIM PacifiCorp balances its system 60 minutes in advance instead of 30 minutes. PacifiCorp adds that counterparties do not want to part with resources that might be needed and there are higher prices for purchases.

3. *Double Counting with Integration Costs*

ICNU contends that, if we retain the DART adjustment, then day-ahead wind and load integration costs should be removed from NPC because they are being double counted ($1.9 million reduction). ICNU explains that the DART adjustment incorporates actual historical purchases and sales, including the real costs associated with day-ahead wind and load integration from those historical transactions. ICNU adds that the day-ahead integration costs relate to the balancing cost for the difference between the day-ahead resource commitment and the actual commitment of wind and load. ICNU states that the DART adjustment calculates the $/MWh cost of system balancing but does not remove the transactions that were made for the purpose of day-ahead load and wind integration.

PacifiCorp responds that inter-hour integration costs calculated in the 2014 wind integration study are the system balancing costs primarily resulting from differences between day-ahead unit commitment and actual dispatch commitment of gas plants, not market transactions considered in the DART.

4. *Resolution*

We reaffirm and uphold our decision in Order No. 15-394 approving PacifiCorp's system balancing adjustment. The DART adjustment—while not perfect—reasonably addresses a deficiency of the GRID model and is likely to more fully capture PacifiCorp's net variable power costs.

We decline to adopt Staff and CUB's recommendation that we eliminate the adjustment now and direct PacifiCorp and parties to work on substitute modeling adjustments to better simulate buy and sell balancing transactions for future TAM proceedings. No persuasive evidence was offered to convince us that our decision last year was in error. We also find that four years of data is sufficient to generate a normalized result and that PacifiCorp's adjustment is based on an analysis of a reasonable set of transactions.[15]

Similarly, we decline ICNU's proposed wind integration adjustment and accept PacifiCorp's explanation that the wind integration study and DART are capturing different system costs related to balancing and are additive. The company explains that the day-ahead integration charge primarily accounts for additional operating reserves and less than optimal resource dispatch due to day-ahead forecast uncertainty.[16] The DART adjustment is designed to capture

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[16] PacifiCorp Reply Brief at 33 (Oct 5, 2016).

only the price difference between the average market price and the company's actual prices for balancing transactions. DART is initially applied as an adder to increase market prices, and the wind integration costs are applied as a separate out-of-model adjustment for the added integration costs of wind integration.

Last, as further explained in our discussion of next steps below, we direct PacifiCorp, Staff, and other parties to meet informally to examine the DART adjustment in detail and provide parties opportunities to offer and discuss potential alternative modeling approaches.

D. Energy Imbalance Market (EIM) Benefits

In the 2017 TAM, PacifiCorp estimates $4.84 million in inter-regional EIM benefits, $1.13 million in flexibility reserve benefits, and $1.56 million in EIM costs, all on an Oregon-allocated basis, for a net 2017 benefit of $4.41 million for Oregon customers.[17]

Staff and CUB dispute PacifiCorp's estimates for inter-regional benefits. They believe the estimates should be increased so they are closer to CAISO's calculation and that *intra*-regional benefits should also be added to the TAM. Staff and CUB also believe that the company's methodology is too complex and lacks transparency, and believe that a separate, independent investigation on the modeling of EIM benefits is necessary.

1. Inter-regional Benefits, Methodology, and Transmission Capacity

Staff and CUB maintain that the company's calculation of EIM inter-regional benefits grossly understates actual benefits, and that customers should receive the actual benefits that are reported by CAISO for the current year.

Staff argues that PacifiCorp's inter-regional EIM benefits are understated because the company is not using actual production costs. Staff believes actual production costs consist of the marginal cost, or the variable cost of the power plus operating and maintenance costs. Staff maintains that PacifiCorp uses bid prices for thermal resources, replacement costs for hydro units, and a value for wind facilities based on curtailment payments, lost PTCs, and the value of the lost RECs. Staff believes that for the renewable hydro and wind facilities, the marginal cost to produce a MWh should be zero. Staff explains that PacifiCorp's calculations use a bottom-up approach with a tremendous amount of data and prices instead of actual production costs.

[17] PAC/400, Dickman/56; PAC/405, Dickman/1. The parties discuss EIM values on a total company basis, and any total company figures have been adjusted by Oregon's 2017 allocation factor of 25.230 percent for purposes of this order.

CUB argues that the company underestimates EIM benefits by limiting EIM transfers based on the available transmission in the forecast test period. CUB and Staff recommend that we adopt the method employed by the company for NV Energy that uses historical sales, not historical transmission allocation to forecast EIM inter-regional benefits on an annual basis.

With regard to Staff's arguments, PacifiCorp responds that its filing uses the same methodology we found reasonable in the 2016 TAM, and is further refined to identify the specific incremental resources used. PacifiCorp explains that benefits of exports are equal to the revenue received less the production cost of the resource. Benefits of imports are the import expense less the expense of the generation that would have been dispatched otherwise. The production cost used is the marginal cost to produce an additional megawatt-hour at a given resource, which is equal to the resource bids submitted to the EIM. In response to Staff and CUB's argument that the EIM bids include adders, the company states that the only adder is a small percentage adjustment to account for the possible change in natural gas prices or other costs typically incurred over time such as pipeline charges.

In response to CUB's arguments, PacifiCorp explains that EIM exports use limited California-Oregon intertie transmission capacity, so if NPC includes forward transactions at the California-Oregon border, there will be less transmission available for EIM exports. PacifiCorp states that it used the actual historical EIM benefits, divided by the total transmission that was available for the EIM during the historical period, and expressed in dollars per megawatt-hour of available transmission. This margin is then applied to the transmission in the 2017 TAM that is available for EIM.[18] PacifiCorp states this approach ensures that the same transmission capacity is not improperly used for both sales to the California-Oregon border market and EIM.

2. Intra-regional Benefits

Staff and CUB argue that PacifiCorp should also include a third type of benefits—intra-regional benefits. They define intra-regional benefits as PacifiCorp's more efficient dispatch within its own balancing authority area (BAA). PacifiCorp does not include intra-regional benefits in the TAM because it states that GRID has always reflected perfectly optimized dispatch.

Staff points to CAISO's benefit calculation that includes intra-regional benefits by comparing a less efficient counterfactual dispatch to EIM dispatch. Staff believes that CAISO's counterfactual dispatch is nearly identical to GRID, because it is a less-efficient, more costly method of dispatch compared to the EIM and because it uses resources that can ramp quickly.

[18] PAC/400, Dickman/77.

CUB believes the company has not met its burden of proof that intra-regional benefits should be zero. CUB recommends that we either adopt CAISO's benefit calculation, or find that the company's forecast of zero and CAISO's forecast of $6.61 million (Oregon allocated) represent the potential range of 2017 intra-regional benefits, and use the midpoint as a reasonable estimate for ratemaking. This midpoint can be used until there is an investigation on the modeling of EIM benefits.

CUB and Staff also argue that PacifiCorp is realizing intra-regional benefits from the five-minute market that are not reflected in GRID's hourly model. CUB and Staff state that even if GRID is perfectly optimized, the sub-hourly transactions facilitated by the EIM offer more efficiencies since the EIM can dispatch across the hour, while ramping resources to meet the next hour.

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 in GRID. Regarding CAISO's calculation of intra-regional benefits, PacifiCorp states the counterfactual is not the same as GRID but is closer to the manual, less efficient pre-EIM dispatch.

3. Resolution

We accept PacifiCorp's 2017 EIM benefit calculation of $4.41 million net of costs, reflecting inter-regional and flexibility benefits on an Oregon-allocated basis, and decline the proposed adjustments.

We find PacifiCorp's estimates of inter-regional benefits reasonable. PacifiCorp refmed its modeling of inter-regional benefits using 12 months of actual results and a resource stacking method that specifies the actual resources used for EIM facilitated transfers.[19] This modeling refinement plus incorporation of actual results from NV Energy participation in the EIM resulted in higher inter-regional benefits in 2017 as compared to 2016. PacifiCorp rebutted Staff's claims about the lack of use of actual production costs by showing that the resource bid prices equal the marginal resource cost (or production cost of that resource) plus a small adder that accounts for changes in certain cost drivers over time.

We find that the GRID forecast already accounts for intra-regional benefits because the model optimizes dispatch on an hourly basis. The company explains that modeling dispatch on a sub-hourly basis would yield additional benefits by claiming that modeling of five-minute dispatch would increase net variable costs. PacifiCorp also effectively rebuts the argument that the GRID and CAISO "counterfactuals" are functionally equivalent. PacifiCorp points out that the CAISO

[19] PAC/400, Dickman/71.

counterfactual aims to mimic the manual dispatch at a subset of power plants that occurred before the EIM was put in place.

In addition, we concur with PacifiCorp that it appropriately accounts for transmission constraints in its modeling and decline CUB's proposed adjustment. PacifiCorp's calculation has not changed since the 2016 TAM.

Finally, as further explained under our discussion of next steps below, we accept PacifiCorp's offer to hold workshops to discuss the company's EIM modeling in depth and provide opportunities for parties to propose refinements to those methodologies.

E. Qualifying Facility (QF) Contracts

1. Parties' Positions

CUB and Staff propose changes to how PacifiCorp models new QF contracts in the TAM. Currently, PacifiCorp uses an attestation process that was agreed to by the parties in the 2015 TAM stipulation. Under this process, PacifiCorp includes in its modeling only those new QF contracts for which the utility has a commercially reasonable good faith belief that the QF will commence commercial operations during the test period. The QF cost is then pro-rated to reflect the expected operation date.

CUB and Staff propose that this method be modified to account for the fact that, despite the attestations, not all QFs become operational by the end of the test year. CUB and Staff propose the company apply a discount factor based on the historical difference between forecasted and actual energy generation from new QFs, or, as Staff describes it, the difference between forecasted QFs becoming operational in the year and actual QFs with contracts at the beginning of the year. CUB proposes a specific discount factor—that we limit the company to 93 percent of the new QF contracts, based on past performance. ICNU supports a historical success factor.

In support of its recommendation, CUB explains that QF contracts are a significant driver of NPC increases, accounting for $99 million in total-company NPC increase this year.[20] CUB recognizes that the company must sign any QF contract presented to it at avoided cost rates. However, CUB states that, with the expectation of avoided costs decreasing in the future, QFs are rushing to get contracts signed and, under the current attestation process, customers will pay increased power costs for certain QF contracts that will not come online during the test year. In response, PacifiCorp states that it models QFs with their expected operational date, and that on average, the TAM has understated the total count of QFs and their volume of energy.

[20] PAC/100, Dickman/10; PAC/400, Dickman/11.

PacifiCorp provided information on the new QFs expected to come online in 2016, as well as year-by-year information on the total amount of system QFs forecasted and actuals, both of which show forecasts close to actuals.[21]

2. Resolution

We decline to apply any discount factor at this time for new QF contracts. As discussed above, the attestation process for QF contract costs was adopted as part of the 2015 TAM stipulation. Under that agreement, PacifiCorp confirms in its November indicative update those new QFs it reasonably believes will reach commercial operation during the rate effective period, and also updates the expected commercial operation dates to reflect project delays.[22]

We acknowledge CUB's undisputed claim that only 80 MW of the 96 MW of new QF generation that was forecasted for this year has become operational.[23] As CUB concedes, however, we do not yet have concrete data to fully evaluate the 2016 forecast accuracy, because many of the QFs are forecast to begin operation at the end of the calendar year. Because PacifiCorp has shown that, from 2008 to 2015, the company's overall QF forecast has averaged out below the actual QF production, we will allow the attestation process to continue.

We appreciate the parties' oversight of the QF costs, and will further consider this issue when additional data is available to evaluate PacifiCorp's use of the attestation method.

F. Avian Protection Compliance Adjustment

1. Parties' Positions

Staff challenges PacifiCorp's decision to reduce generation at two wind sites (Glenrock and Seven Mile Hill) to reflect anticipated energy lost from implementing avian protection curtailments to comply with a court order. Staff contends that new information shows that PacifiCorp knew or should have that avian-related curtailments were possible, and that ratepayers should be held harmless from the company's decision to proceed with developing these sites.

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[21] PAC/400, Dickman/88; PAC/800, Dickman/42; PAC/805.

[22] *In the Matter of PacifiCorp's 2015 Transition Adjustment Mechanism*, Docket No. UE 287, Order No. 14-331 at 5, App A at 7 (Oct 1, 2014) ("Attestation for Qualifying Facility (QF) Contracts. The Settling Parties agree that the attestation included with PacifiCorp's Indicative Update in TAM proceedings will include a statement confirming that, for the executed power purchase agreements (PPAs) with new QFs included in the TAM, PacifiCorp has a commercially reasonable good faith belief that these QFs will reach commercial operation during the rate effective period based on the information known to the company as of the contract lockdown date. This attestation language does not require PacifiCorp to opine on the commercial viability of any of these QFs.").

[23] CUB/100, McGovern/21-22; PAC/400, Dickman/86.

Staff's argument is based on new evidence demonstrating that PacifiCorp knew, or should have known at the time of siting the wind farms, that there was relevant agency guidance on avoiding and minimizing avian take by wind facilities. Staff contends, although it is within PacifiCorp's discretion to abide by or ignore such guidance, ratepayers should not be disadvantaged by the company's gamble on these enforcement actions that would reduce the output of these facilities. Staff emphasizes that this information was not introduced during our earlier prudence review of these wind projects. Staff contends that there is no indication that the parties or the Commission was aware in that rate proceeding[24] that the projects were intentionally sited contrary to agency guidance, or that PacifiCorp evaluated the cost of this siting.

Staff asserts that, because we approved these projects based on the capacity factor without the avian curtailments, it would not be fair to allow PacifiCorp to reduce this capacity factor to account for these anticipated but undisclosed curtailments. To hold ratepayers harmless, Staff recommends a $249,114 total company reduction (approximately $65,000 for Oregon).

In response, PacifiCorp points to the 2016 TAM, where we rejected a similar adjustment proposed by ICNU.[25] PacifiCorp also defends it actions, indicating that the curtailments are mandated by a court order, that at the time the projects were being built, there had never been an enforcement action against a wind project, and that the parties were aware that the projects were sited in an avian sensitive area during the proceeding that brought the projects into rates.[26] PacifiCorp maintains that no party to that proceeding challenged the prudence of the projects based on avian curtailment risk and that we found both projects prudent and we should not revisit this issue.

2. Resolution

We accept Staff's adjustment to reduce the company's NPC forecast by approximately $65,000 on an Oregon-allocated basis, an amount that is associated with the avian curtailment costs.[27] Although we rejected a similar adjustment in the 2016 TAM, the new undisclosed evidence of PacifiCorp's actual or constructive knowledge of possible avian curtailments convince us that an adjustment is necessary to hold ratepayers harmless.[28] Our decision does not constitute a hindsight prudence review of these facilities. The company's avian curtailment costs are similar to forecasted costs associated with a plant outage, and we are limiting PacifiCorp's ability to

[24] *In the Matter of PacifiCorp's 2009 Renewable Adjustment Clause*, Docket No. UE 200, Order No. 08-548 (Nov. 11, 2008).
[25] Order No. 15-394 at 7 ("First, PacifiCorp must comply with the court order for avian protection.").
[26] *See* PAC/800, Dickman/30.
[27] PacifiCorp NPC Indicative Update, Exhibit B at 1 (Nov 8, 2016) (removed lost energy from avian protection curtailment, decreasing net power cost by approximately $65,000 on an Oregon-allocated basis).
[28] Staff/200, Kaufman/18; Staff/205, Kaufman/18 (Wyoming plea agreement and joint statement of facts).

reduce its forward-looking NPC for reasons that the company knew or should have known about restrictions on operations at the time it was siting these wind facilities.

G. Direct Access Issues

As part of the TAM process, we establish rates for PacifiCorp's large non-residential customers that may elect to leave PacifiCorp's cost-based service and choose to receive their energy from direct access providers. Customers that participate in PacifiCorp's direct access program are subject to three potential annual cost components. All direct access customers (one-year, three-year, and five-year) are subject to a transition adjustment and a Schedule 200 fixed generation charge. Customers in the five-year program also pay an opt-out charge.

- The transition adjustment is the difference between PacifiCorp's net power cost (as reflected in Schedule 201) and the estimated market value of the electricity that is freed up when a customer chooses direct access service.[29] Currently, this is a small credit to the customer.

- The Schedule 200 charge represents the company's fixed-generation costs, updated in the TAM. A direct access customer is required to pay this as it represents PacifiCorp's stranded fixed-generation costs.

- The Schedule 296 opt-out charge, applicable to five-year program customers, is calculated by bringing forward into years one through five the projected Schedule 200 costs for years six through ten, net of projected net power cost savings attributed to the departed load.

According to Noble Solutions, a five-year direct access participant in 2017 will, in year one, receive a transition credit of $1.76 MWh, pay a Schedule 200 charge of $26.73 MWh, and pay a Schedule 296 opt-out charge of $13.37 MWh. The customer would be subject to these cost components for each of the five years of the program.

Noble Solutions requests that PacifiCorp's transition adjustment and opt-out charge be reduced in two ways. First, Noble Solutions asks that the transition adjustment be credited for the value of RECs freed up by the departing direct access customer. Second, Noble Solutions recommends that the opt-out charge in the five-year program be reduced to account for the impact of accumulated depreciation. We address each proposal separately.

[29] OAR 860-038-0005(41) Ongoing valuation method determines the transition costs or benefits for a generation asset by comparing the value of the asset output at projected market prices for a defined period to an estimate of the revenue requirement of the asset for the same time period.

1. REC Adjustment

a. Parties' Positions

Noble Solutions requests that the transition charges in the one-year, three-year, and five-year programs include a credit for freed-up RECs during the transition period. Noble Solutions argues that, when a direct access customer departs PacifiCorp's system, RECs that were previously acquired by PacifiCorp to serve that load are freed up for other uses.

Noble Solutions acknowledges that the direct access customer is credited for the assumed value of the freed-up energy from PacifiCorp's portfolio, but contends that the valuation method does not account for the value of renewable attributes or RECs. To properly account for these freed-up RECs, Noble Solutions request that we first value an unbundled REC at $1 each. Then, we should multiply that value by 15 percent (the RPS compliance percentage requirement for 2017 met by PacifiCorp's resources) and add $0.15 to the weighted average market price of freed-up energy in the TAM calculation. Alternatively, Noble Solutions asks that PacifiCorp transfer to the alternative electricity service supplier (ESS) the RECs that are freed up as a result of direct access, and explains that in 2015 this was approximately 31,200 RECs.[30]

In response, PacifiCorp points to last year's TAM, where we found that Noble Solutions' formula for valuing freed-up RECs assumed PacifiCorp would sell its RECs, when in fact, PacifiCorp banks its RECs. We also explained that, to the extent RECs are sold, proceeds flow back to customers, and that the net present value of any freed-up RECs is *de minimis*.[31] PacifiCorp states that our findings are still true today, and that the increased RPS obligation from SB 1547 makes it more likely that the company will continue to bank its RECs. Staff agrees and supports PacifiCorp's arguments.

PacifiCorp also asserts that there is no reliable basis to value the freed-up RECs. With the passage of SB 1547, PacifiCorp states, the valuation problem has become more intractable because RECs can have different values and there is no reasonable basis to assume which RECs were freed up by the departing customer.

b. Resolution

We decline Noble Solutions' proposed adjustments to reflect the value of reduced RPS obligations.

[30] Noble Solutions/200, Higgins 6-7.
[31] Order No. 15-394 at 12.

In the near term, we see little or no benefit from a reduction in RPS obligation due to the loss of load from direct access. PacifiCorp has ample resources to comply with the RPS through the mid- to late-2020s; a "freed-up" REC today simply adds to the surplus of RECs that PacifiCorp already has or will have to comply with the RPS. Further, PacifiCorp has stated that it will continue to bank RECs rather than sell them, so there is no benefit to other customers from a potential sale of RECs.

Over the long run, if there is a guaranteed loss of load due to direct access, then there may be benefits to other customers by altering the point in time when PacifiCorp would need to take resource actions to comply with the RPS. However, based on the record, PacifiCorp would not need to take such action to ensure compliance with the RPS until the mid-2020s. No party has offered a reliable way to estimate the value of loss of load in that time period and we note the complexities to derive such an estimate. We also find that any reasonable estimate of benefits from that time period would be *de minimis* when discounted to today's dollars.

Finally, as further addressed below, we direct PacifiCorp, Staff, and the parties to further discuss REC valuation in the party workshops, with a focus on the potential benefits that may derive at the time PacifiCorp must take substantive action to comply with its RPS targets.

2. Consumer Opt-Out Charge

a. Parties' Positions

As noted above, the Schedule 296 Consumer Opt-Out Charge applies to the five-year program, and is a projection of what Schedule 200, fixed generation costs, would be for years six through ten brought forward into years one through five. Noble Solutions asserts that, when calculating this charge, fixed generation investments in Schedule 200 should be frozen after year five and should decline each year from year six through ten to reflect accumulated depreciation. Noble Solutions acknowledges that we declimed this adjustment in the 2016 TAM order, but has appealed that decision and renews its arguments again here.

Noble Solutions states that Oregon's direct access law limits the transition charges to the pool of generation investments that "were" incurred on the customer's behalf, "prior to" the customers' direct access election. Noble Solutions' recommendation is based on its assertion that after year five, the fixed generation assets are "frozen" and therefore should decline due to accumulated depreciation. Noble Solutions maintains that the opt-out charge should decline by 2.36 percent per year to account for accumulated depreciation for a closed pool of generation six to ten years after a permanent opt-out election.

PacifiCorp responds that we have repeatedly found that the prohibition of cost shifting requires that the company forecast its fixed generation costs for a full ten years and recover those costs through Schedule 200 (reflecting actual fixed generation costs in years one through five) and through the opt-out charge (reflecting forecasted fixed generation costs in years six through ten). PacifiCorp states there are many costs to operate and maintain existing generation assets that increase over time and offset the impact of accumulated depreciation, such as overhauls, capital expenditures for maintenance, and union labor contracts.

Staff believes this issue should be rejected because it was decided in the 2016 TAM.

b. Resolution

We decline Noble Solutions' recommendation that the Consumer Opt-Out Charge should decrease in years six through ten, and reaffirm our findings from the 2016 TAM.[32]

Based on the record, we find PacifiCorp's forecast of fixed generation costs to be reasonable. Essentially, PacifiCorp takes its fixed generation costs as of year one, escalates those costs at an inflationary rate to estimate years six through ten, factors in the costs or benefits of freed-up energy, and converts the resulting amount into an annual charge that is assessed during the departing customer's five-year opt-out period. PacifiCorp explains that the consumer opt-out charge includes other costs that escalate over time and more than offset the impact of accumulated depreciation. Thus, based on the record, the assumption that fixed generation costs increase at the rate of inflation is reasonable.

For the next TAM proceeding, we direct PacifiCorp to provide a historical time series of fixed generation costs broken down by its components (*e.g.*, capital, O&M) as a check on the reasonableness of its forecasts.

H. Next Steps

In this and prior TAM proceedings, Staff and the intervenors have expressed continuing concerns about the complexity of PacifiCorp's GRID model and external adjustments. We acknowledge these concerns about the complexity of PacifiCorp's modeling, which are compounded by the compressed annual schedule we use to review PacifiCorp's TAM filings. At the same time, we recognize that the GRID model is complex because PacifiCorp's system is, in fact, a complex system to model. Because power costs are a key component of utility rates, we expect

[32] Order No. 15-394 at 12 ("PacifiCorp explains that incremental generation is not added after year five. PacifiCorp also explains that, in real (inflation-adjusted) terms, the fixed generation costs are held constant through year 10. As we did in previous orders, we find it reasonable to assume that fixed generation costs will increase at the rate of inflation after year five."). This issue is pending appeal before the Oregon Court of Appeals.

PacifiCorp to update its prospective power costs using a high degree of technical analysis. We would likely criticize the company for any effort to update these costs using a less sophisticated, more simplistic methodology.

Although our primary concern is that the GRID model produces accurate results, we also aim to ensure that PacifiCorp's power cost modeling is as transparent as possible and, to the extent possible, verifiable by the Commission and the parties. To help address that concern, we direct PacifiCorp, Staff, and the parties to meet informally to address three GRID issues discussed in the introduction of this order.

IV. ORDER

IT IS ORDERED that:

1. Advice No. 16-05 is permanently suspended.

2. PacifiCorp, dba Pacific Power, shall update its net power costs to reflect the changes adopted in this order to establish its Transition Adjustment Mechanism NPC for calendar year 2017 and file its tariffs to be effective January 1, 2017.

3. PacifiCorp, dba Pacific Power, shall delay filing of its long-term fuel supply plan for the Jim Bridger coal plant. We direct PacifiCorp, Staff of the Oregon Public Utility Commission and the parties to informally meet and discuss (1) the information and analyses needed to meaningfully evaluate PacifiCorp's long-term fuel supply plan for the Jim Bridger coal units in future Transition Adjustment Mechanism (TAM) proceedings, as well as (2) whether additional information and analyses should be provided to Staff and the parties regarding PacifiCorp's fuel plans for any of its other coal-fired units, as discussed in the body of this order. We direct Staff to report back to us on the results of those discussions, with any recommendations, at our January 24, 2017 Public Meeting.

4. We direct PacifiCorp, dba Pacific Power, Staff of the Oregon Public Utility Commission, and the parties to participate in workshops to examine the following GRID issues: (1) Day-Ahead/Real-Time Transaction (DART) adjustments, (2) Energy Imbalance Market (EIM) benefit estimation, and (3) REC valuation, as discussed in the body of this order. Staff shall report back to us on the results of those discussions before PacifiCorp's 2018 TAM is filed.

5. For the next TAM filing, we direct PacifiCorp, dba Pacific Power, 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.

Made, entered, and effective DEC 20 2016.

Lisa D. Hardie
Chair

John Savage
Commissioner

Stephen M. Bloom
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

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.