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August 1, 2016

VIA ELECTRONIC FILING
AND COURIER DELIVERY

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

Re: UE 307 – PacifiCorp Reply Testimony and Exhibits

PacifiCorp d/b/a Pacific Power hereby submits for filing the Reply Testimony and Exhibits of Brian S. Dickman, Dana M. Ralston, R. Bryce Dalley and Judith M. Ridenour. Included with this filing is a CD containing the electronic workpapers and confidential information.

PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
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Please direct informal correspondence and questions regarding this filing to Natasha Siores at (503) 813-6583.

Confidential material in support of the filing has been provided to parties under the protective order in this docket (Order No.16-128).

Sincerely,

RBDalley

R. Bryce Dalley
Vice President, Regulation

Enclosures

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Reply Testimony in Docket UE 307 on the parties listed below via e-mail and/or overnight delivery in compliance with OAR 860-001-0180.

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Dated this 1st day of August 2016.

Jennifer Angell

Jennifer Angell
Supervisor, Regulatory Operations

Docket No. UE 307
Exhibit PAC/400
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Brian S. Dickman

August 2016

REPLY TESTIMONY OF BRIAN S. DICKMAN

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ATTACHED EXHIBITS

Exhibit PAC/401 – TAM Allocation Reply Filing 2017

Exhibit PAC/402 – Results of Updated NPC Study Reply Filing 2017

Exhibit PAC/403 – Corrections and Updates Summary Reply Filing 2017

Exhibit PAC/404 – Other Revenue Reply Filing 2017

Exhibit PAC/405 – EIM Costs Reply Filing 2017

Exhibit PAC/406 – EIM Inter-Regional Benefits Reply Filing 2017

Exhibit PAC/407 – Staff Response to PacifiCorp Data Request 2

Exhibit PAC/408 – Staff Response to PacifiCorp Data Request 12

Exhibit PAC/409 – CONFIDENTIAL Staff Response to PacifiCorp Data Request 4

Exhibit PAC/410 – CUB Response to PacifiCorp Data Request 1

Exhibit PAC/411 – CAISO Technical Bulletin "Quantifying the Benefits of Participating in EIM"

Exhibit PAC/412 – CAISO 2016 Q1 Report "Benefits for Participating in EIM"

Exhibit PAC/413 – CUB Response to PacifiCorp Data Request 7

Q. Are you the same Brian S. Dickman who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. My testimony has two sections. First, I provide a Transition Adjustment Mechanism (TAM) update (Reply Update), as allowed under TAM Guidelines adopted by the Public Utility Commission of Oregon (Commission) in Order No. 09-274 and revised in Order Nos. 09-432 and 10-363. In the Reply Update, I explain the reasonableness of the Company's revised Oregon net power costs (NPC) of $375.5 million for the test period of the 12 months ending December 31, 2017.[1] I provide corrections and contract, fuel and forward prices curve updates to the Company's April 1, 2016 filing (Initial Filing).

Second, my reply testimony responds to various issues and adjustments raised in the Opening Testimony of Commission Staff (Staff) witnesses Mr. John Crider and Mr. Lance Kaufman, the Citizens' Utility Board of Oregon (CUB) witness Ms. Jamie McGovern, the Industrial Customers of Northwest Utilities (ICNU) witness Mr. Bradley G. Mullins, and Noble Americas Energy Solutions LLC (Noble Solutions) witness Mr. Kevin Higgins.

Q. Please identify the other witnesses providing reply testimony supporting the 2017 TAM.

[1] Unless otherwise specified, references to NPC throughout my testimony are expressed on an Oregon-allocated basis.

A. There are three other witnesses providing reply testimony in support of the Company's 2017 TAM filing: Mr. R. Bryce Dalley, Mr. Dana M. Ralston, and Ms. Judith M. Ridenour.

Q. Please summarize your reply testimony.

A. In Order No. 15-394 in docket UE 296 (the 2016 TAM), the Commission approved the Company's modeling adjustment for system balancing transactions, ordered the Company to maintain that adjustment (and all other NPC modeling) unchanged in the 2017 TAM, and directed the Company to work with the parties to assist their understanding and review of the system balancing transaction adjustment.

Consistent with Order No. 15-394, the Company reflected the system balancing transaction adjustment in the 2017 TAM and worked with parties to support their analysis of the adjustment. One year later, Staff, CUB, and ICNU again oppose the adjustment. But the parties rely on the same evidence and arguments, propose no concrete alternatives to the Company's modeling, and provide no evidence that the NPC forecast is more accurate without the adjustment.

My testimony shows that there is no change in the key factors underlying the Commission's adoption of the system balancing transaction adjustment. The Company incurs system balancing costs that are not reflected in the Generation and Regulation Initiative Decision Tools model (GRID) and the system balancing transaction adjustment captures those costs and produces a more accurate estimate of NPC. I support the necessity and reasonableness of continued application of the system balancing transaction adjustment in the TAM.

Staff and CUB also challenge the Company's coal plant dispatch modeling, in particular the recognition of minimum take requirements in third-party coal supply agreements. Staff agrees that minimum take requirements impose real costs, but claims the Company introduced a prohibited new modeling adjustment. I explain that the Company's modeling of minimum take requirements here is the same as in past TAMs, so there is no basis for Staff's proposed disallowance.

CUB claims that the Company's recent coal supply agreements are imprudent and the minimum take requirements in those contracts should be disregarded in this case. But none of the contracts CUB challenges are subject to the minimum take modeling adjustment in either the Initial Filing or the Reply Update because the generating units they supply utilize more than the minimum volume of coal. Even if CUB's claim of imprudence had merit (which it does not), there is no adjustment in this case.

The Company's modeling of the Energy Imbalance Market (EIM) benefits is consistent with its approach in last year's TAM and represents a reasonable (and increasing) estimate of these benefits based on more recent history of EIM operation. I respond to several EIM-related adjustments from Staff and CUB as follows:

- Staff and CUB claim that the TAM should reflect greater intra-regional dispatch benefits based on reports from the California Independent System Operator (CAISO). My testimony explains why the EIM benefits calculated by the CAISO do not reflect greater intra-regional benefits than those already included in the NPC developed by the fully optimized GRID model.

- Staff also recommends an adjustment to EIM inter-regional benefits, claiming that the Company is calculating these benefits as the difference between the revenue earned from an EIM transaction and the aggregated bid prices, rather than the actual costs of production. Contrary to Staff's understanding, however, the Company does calculate the inter-regional benefits based on the cost of production and therefore the Company calculates the inter-regional benefits exactly as Staff recommends.

- CUB recommends two inter-regional benefit adjustments—one related to the purported inclusion of opportunity costs as an offset to EIM benefits and one related to the purported reduction in benefits for transmission utilization. But the Company does not discount the inter-regional benefits based on opportunity costs or transmission utilization factors and therefore CUB's argument has no basis in fact.

Staff also seeks to reverse two other modeling refinements approved in last year's TAM. First, Staff claims that the Company was imprudent for siting two wind plants in an avian-sensitive area and therefore the TAM should not reflect avian-related generation curtailment. Modeling the avian curtailment results in a more accurate wind generation forecast, and even with the curtailment, these wind plants have high capacity factors and remain prudent investments. Second, Staff also claims that the outage rate modeling approved in the 2016 TAM creates inflated NPC by modeling frequent start-ups. But the NPC modeling does not include these start-up costs, so the Company's outage rate modeling cannot inflate them. Moreover, the Company's modeling results in *lower* NPC than Staff's proposal, undermining Staff's claim that the Company is inflating NPC.

CUB recommends that the Commission disallow recovery of all QF contracts that are not commercially operational by the Final TAM Update because QFs consistently come on-line later than expected. But CUB misunderstands how

QFs are modeled and, contrary to CUB's claims, the Company's QF modeling accurately reflects the timing of QF generation. CUB's testimony also fails to discuss the attestation process now in place for QF contracts or explain why that process is now inadequate.

Finally, Noble Solutions raises the same two direct access adjustments proposed in last year's TAM—once again asking the Commission to include the value of freed-up Renewable Energy Certificates (REC) in the transition adjustment and reduce the Consumer Opt-Out Charge to account for accumulated depreciation. Noble Solutions, however, has presented no additional evidence or argument to support a reversal of the Commission's decision, which has now been affirmed twice—in dockets UE 267 and UE 296.

Q. Is the Company's revised NPC recommendation in this case reasonable?

A. Yes. The Reply Update reflects the most recent information available to the Company in the determination of 2017 NPC and sets a reasonable and realistic NPC baseline for 2017.

Q. Is it important to set the most accurate NPC forecast possible to meet the Commission's goals for the TAM and the Company's power cost adjustment mechanism (PCAM)?

A. Yes. The purpose of the TAM is to "produce the best possible estimates of all components of net power costs"[2] so that the Commission can capture costs associated with direct access and prevent unwarranted cost shifting.[3] The TAM

[2] *In the Matter of PacifiCorp d/b/a Pacific Power 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 7 (Oct. 29, 2012).
[3] *In the Matter of Pacific Power & Light Company, d/b/a PacifiCorp Request for a General Rate Increase*, Docket No. UE 170, Order No. 05-1050 at 21 (Sept. 28, 2005).

transition adjustments are calculated by comparing the value of energy used to serve direct access loads with the cost of service rate under the customers' specific energy-only tariff. The Commission adopted an annual NPC update to ensure that both the value of freed-up energy and the cost of service rate are calculated for the same period using the same data. In addition, the more accurate the NPC forecast is in this case, the less likely it is that the Company will need to adjust rates through a PCAM surcharge or surcredit in 2018.

Q. Does the Company's NPC modeling over-state the actual costs to serve customers, as the parties explicitly and implicitly argue here?

A. No. On the contrary, the Company has persistently under-recovered its NPC in the TAM. Going back to at least 2008, the Company's NPC in rates have been substantially less than the Company's actual NPC, despite the Company's efforts to minimize NPC, notably through participation in the EIM. In 2015, the Company under-recovered its NPC by $18.3 million. This exceeds the 2017 TAM increase of $16.2 million included in the Company's Reply Update, as described below.

Figure 1
Actual NPC vs. NPC Collected in Rates

Year	OR NPC Collected Through Rates	OR Actual NPC	Under Recovery of OR NPC
2008	$ 252,556,048	$ 286,401,464	$ 33,845,416
2009	248,429,624	261,335,991	12,906,367
2010	241,238,092	276,837,681	35,599,589
2011	301,662,279	333,544,839	31,882,559
2012	336,201,734	351,814,385	15,612,651
2013	348,474,235	382,126,867	33,652,632
2014	341,351,338	377,421,181	36,069,843
2015	343,993,011	362,384,220	18,391,209

REPLY UPDATE

Q. In the Initial Filing, the Company requested NPC of $379.2 million for the test period ending December 31, 2017. How has your NPC recommendation changed?

A. Test period NPC decreased from $379.2 million to $375.5 million, a $3.7 million reduction from the Initial Filing. On a total company basis, NPC decreased by $12.7 million, from $1.567 billion to $1.554 billion.

Exhibit PAC/401 shows that the Company's Reply Update proposes a rate increase of $16.2 million or 1.3 percent overall. The results of the Company's updated NPC study are provided in Exhibit PAC/402. A list of all corrections and updates made, along with the approximate impact of each on NPC, is provided in Exhibit PAC/403. Exhibits PAC/404, PAC/405, and PAC/406 present updated information for Other Revenue, EIM costs, and EIM inter-regional benefits, respectively, as contained in the Company's Reply Update.

Q. Please explain the changes reflected in your revised NPC request.

A. First, the Company made corrections to the Initial Filing and updated the Company's proposed NPC with: (1) the most recent official forward price curve (OFPC) and short-term firm transactions; (2) new power, fuel, and transportation/transmission contracts and updates to existing contracts, and (3) EIM benefits based on additional operational experience, including benefits associated with NV Energy (NVE). Second, as described in further detail later in my testimony, for this case only, the Company accepts CUB's proposed adjustment to remove the NPC impact of the selective catalytic reduction systems

(SCR) investments at Jim Bridger Units 3 and 4.

Q. Do the updated market prices in the Reply Update directly impact certain of the parties' adjustments in this case?

A. Yes. First, as addressed in greater detail below, the higher OFPC increased the dispatch of the Company's coal plants and reduced the need to adjust coal contracts to meet contractual take-or-pay provisions. Second, as discussed in the testimony of Mr. Ralston, the Company updated coal costs for the Jim Bridger plant to reflect the increased dispatch, including additional tons from the Bridger Coal Company (BCC) mine as well as the Powder River Basin (PRB). The incremental cost of these additional tons is less than the Black Butte contract and lowers the overall cost of coal at the Jim Bridger plant.

Q. Did the Company previously provide the parties a list of known corrections?

A. Yes. Under the TAM Guidelines, on June 16, 2016, the Company provided a list of corrections known at the time. The current filing incorporates those corrections along with several updates identified since the Initial Filing. The individual corrections and updates and their impact on NPC are identified in Exhibit PAC/403.

Q. Please summarize the major changes in NPC resulting from the Reply Update.

A. Table 1 illustrates the change in total company NPC by category compared to the NPC originally filed in this case.

Table 1
Net Power Cost Reconciliation

	($ millions)	$/MWh
OR TAM 2017 Direct	**$1,566**	**$25.86**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	($92)	
Purchased Power Expense	$50	
Coal Fuel Expense	$47	
Natural Gas Fuel Expense	($17)	
Wheeling and Other Expense	($1)	
Total Increase/(Decrease) to NPC	**($13)**	
OR TAM 2017 July Update	**$1,553**	**$25.65**

The changes in the components of total company NPC from the Initial Filing are largely driven by an increase in the forward market prices for electricity and natural gas. While higher electricity prices increase wholesale sales revenues, this effect is partially offset by an increase in purchased power expense. With higher natural gas prices, gas plants ran less, causing an overall reduction in natural gas fuel expense, while coal plants generated more resulting in higher overall coal fuel expense. Finally, wheeling expense is slightly lower as a result of an expiring wheeling contract.

Q. **Please identify the corrections included in the Company's Reply Update.**

A. Three EIM related corrections to the filed NPC have been identified since the case was filed and each has been incorporated into the Company's Reply Update.

- **Portland General Electric (PGE) EIM Participation Benefit—**The expected benefits associated with PGE's participation in the EIM were calculated in the Company's Initial Filing, but the resulting amount was not reflected in the overall net power costs. Correcting this omission decreases NPC approximately $27,000.

- **EIM Import and Export Resource Costs—**The calculation of EIM benefits is net of the cost of resources that support exports and the savings from resources displaced by imports. In the Initial Filing, the Company calculated these resource dispatch costs independently for both the fifteen-minute market volumes (FMM) and five-minute market volumes (rtd). In fact, generators receive a single dispatch instruction on a five-minute basis reflecting the net market result. The Company also calculated the transmission available based on the sum of FMM and rtd transmission limits for each interval, which overstates the total capacity available. Correcting this calculation decreases NPC by approximately $1.1 million.
- **EIM California Carbon Allowance (CCA) Price—**The Company must acquire CCAs to cover the greenhouse gas emissions associated with its EIM exports to the CAISO. The Company's 2015 weighted average CCA price in the Initial Filing was understated. This correction increases NPC by less than $1,000.

Q. Please explain the updates included in the Company's Reply Update.

A. The Company's Reply Update includes the following updates:

- **Mid-Columbia Hydro Updates—**Douglas Public Utility District provided updated project costs for the fiscal year September 1, 2016, through August 31, 2017, in its preliminary pro-forma published on May

3, 2016. Grant Public Utility District provided an updated estimate of its loads on July 27, 2016, which impacts the Company's share of Grant's annual auction revenues. These updates decrease NPC by approximately $5,000.

- **New QF Contracts—**The Company has executed new QF contracts for the output of one wind project and two solar projects. Also, three small Oregon QFs have terminated their contracts. The terminated QFs contracts are OR Solar (1) LLC, OR Solar (4) LLC, and NorWest Energy 5 (Arlington). This update decreases NPC by approximately $270,000.
- **Black Hills Sale Fixed and Variable Charges—**This update reflects the annual update of the fixed and variable charges for the sales contract with Black Hills Corporation. This update increases NPC by approximately $23,000.
- **Colstrip Transmission—**As part of a settlement agreement with the Bonneville Power Administration (BPA), a portion of the Company's Colstrip transmission rights have been redirected from PACE to PACW. This update increases NPC by approximately $38,000.
- **Pipeline Expenses—**Northwest Pipeline provided an updated cost of service calculation for the Chehalis Pipeline Lateral, with a new monthly payment effective April 2016. This update decreases NPC by approximately $18,000.
- **Wheeling Updates—**By reconfiguring its BPA transmission rights to Oregon loads, the Company has allowed one of its reservations to expire,

effective June 30, 2017. Also, Idaho Power Company and Arizona Public Service Company have released updated tariff rates which will be effective during 2016. These updates decrease NPC by approximately $120,000.

- **Official Forward Price Curve and Short-Term Firm Transactions—** The Company updated the OFPC from March 03, 2016, to June 30, 2016. On average, market prices for electricity at the Mid-Columbia and Palo Verde markets increased by approximately 20 percent. Similarly, market prices for natural gas increased, on average, approximately 23 percent. Short term sales and purchase transactions for electricity and natural gas were also updated through July 1, 2016. These updates increase NPC by approximately $3.5 million.
- **Coal Costs—**Coal costs were updated to reflect changes in prices and volumes. Company witness Mr. Ralston provides additional detail on the update in his reply testimony. The update reduces NPC by approximately $2.6 million.
- **EIM Inter-Regional Transfer Benefit—**The Company's Initial Filing reflected EIM inter-regional benefits based on actual transfers between the CAISO and PacifiCorp during the twelve months ending December 2015. Due to NVE's participation in EIM starting in December 2015, the Company's benefits are fundamentally different after that date. To reflect the best information available concerning the expanded EIM footprint incorporating NVE, the Company has based the EIM inter-regional

transfer benefits in its Reply Update on the twelve months ending May 2016, with adjustments to account for the impact of NVE in the months prior to its participation. The use of a twelve-month historical period captures the seasonal variation in EIM benefits. The updated EIM inter-regional benefits decrease NPC by approximately $1.9 million.

- **EIM Regulation Reserve Benefit**—The Company has updated the EIM flexibility reserve credit inputs to reflect actual results for January through May 2016 with the expanded EIM footprint encompassing the Company, NVE, and the CAISO. The Company's reserve savings increase by 37 MW as a result of this change. This update results in a decrease in NPC of $330,000.

Q. Does the Reply Update include any changes related to the operation of the Hermiston plant?

A. No. In the Initial Filing, the Company flagged the potential need to update the TAM for the final operating protocol reflecting the expiration of its Hermiston purchase contract and the continued receipt of generation related to the Company's 50 percent ownership interest in the plant. Because the Initial Filing accurately captured how the plant is now being operated, there is no need for such an update.

Q. Please describe CUB's recommended adjustment related to the SCRs at Jim Bridger Units 3 and 4.

A. CUB argues that because the fixed costs of the SCRs at Jim Bridger Units 3 and 4 have not been subject to a prudence review in a general rate case, the NPC impact of the SCRs should be removed from the TAM.

Q. Does the Company agree that the TAM cannot reflect the indirect NPC impacts of capital investments in existing plants until they are approved in a general rate case?

A. No. In this case, PacifiCorp is not seeking to include the direct costs of the Jim Bridger SCRs in rates to recover either the return of or return on this investment. Instead, in its Initial Filing the Company just updated its forecast of Jim Bridger's minimum plant capacity to reflect the most accurate and up to date information.

Q. To avoid litigation over the SCR issue, is the Company willing to agree to CUB's adjustment on a non-precedential basis?

A. Yes. To avoid litigation over the SCR issue, the Company is willing to agree to the adjustment to simplify and streamline the resolution of this case.

REPLY TESTIMONY

Compliance with Order No. 15-394

Q. In Order No. 15-394 in the 2016 TAM the Commission directed the Company to work with parties to allow a better understanding of the modeling changes adopted in the order, including for day-ahead and real-time system balancing transactions and thermal plant forced outages.[4] Please explain how the Company has worked with parties in this case to facilitate an understanding of these and other issues in its NPC modeling.

[4] *In the Matter of PacifiCorp's 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 4 (Dec. 11, 2015).

A. The Company has taken a number of steps to ensure an opportunity for a thorough review and evaluation of its NPC modeling in this case:

- In my direct testimony, I included a detailed description and justification of the Company's system balancing transaction and forced outage modeling.
- The Company accelerated production of its work papers underlying its NPC modeling and provided them concurrently with my direct testimony.
- The Company met with Staff on May 5, 2016, to verify their external GRID access was functioning correctly and to provide GRID training.
- The Company presented information on modeling issues in the case (selected with input from parties) at a technical workshop on May 18, 2016. The topics included a detailed discussion of: (1) the calculation of benefits from the EIM; (2) the rationale for the day-ahead and real-time system balancing transaction adjustments, as well as the modeling of these transactions in GRID, including the separation of purchase and sale transactions with adjusted prices for each and the quantification of the volume and cost of additional system balancing transactions; (3) treatment of renewable energy production tax credits (PTC) in the TAM and PCAM; and (4) the effects of the new forced outage modeling on the economic dispatch in the GRID model.
- The Company met with parties at a second technical workshop on June 6, 2016. This workshop included a discussion of modeling the dispatch of coal- and gas-fired generation in GRID, and further discussion of EIM costs and benefits.

- On June 20, 2016, representatives from Staff and CUB attended a tour of PacifiCorp's trade floor in Portland. The Company made available the director of energy supply management (ESM), manager of portfolio optimization, and director of short-term ESM to guide the tour and respond to questions posed by attendees.
- Also on June 20, 2016, PacifiCorp also met individually with a representative of CUB to discuss modeling of day-ahead and real-time system balancing transactions, including details on the Company's approach and responses to conceptual alternatives raised by CUB. The Company agreed to perform alternative GRID runs to evaluate the impact of CUB's suggestions, and to supplement CUB Data Request 30 with the results.
- The Company has responded or is in the process of responding to the 350-plus data requests served to date in this case in a timely and thorough manner, many of which pertain to the Company's proposed modeling.

Q. In Commissioner Bloom's concurring opinion in Order No. 15-394, he requested a Commissioner workshop after the parties' completed their review of the Company's modeling in the TAM. How does the Company intend to comply with this request?

A. The Company plans to work with the Commission to schedule this workshop after it issues its final order in this docket. At that point, the parties will have completed their review and the Commission's participation in the workshop will not be constrained by the pendency of the current litigation.

Q. In Order No. 15-394, the Commission imposed a one-year moratorium on NPC modeling changes. Did the Company comply with this moratorium?

A. Yes. The Company addresses allegations to the contrary (from CUB on the data period for system balancing transactions and from Staff on the minimum take issue) below.

Q. ICNU recommends that the moratorium on modeling changes be extended until the Company files its next general rate case.[5] Do you object to this recommendation?

A. Yes. As noted above, the goal of the TAM is to reflect the most accurate NPC forecast possible. The rapidly changing circumstances in the energy industry and the power markets require modeling flexibility to ensure the forecast accuracy. An extended NPC modeling moratorium is unreasonable in this context.

Day-Ahead and Real-Time System Balancing Transactions

Introduction

Q. Please briefly describe the day-ahead and real-time system balancing transaction adjustment.

A. The adjustment for system balancing transactions was first proposed by the Company in the 2016 TAM. The adjustment has two components: First, to better reflect the market prices available to the Company when it transacts in the real-time market, the Company includes in GRID separate prices for forecasted system balancing sales and purchases. These prices account for the historical price differences between the Company's purchases and sales compared to the monthly average market prices. Second, the Company also reflects additional transaction

[5] ICNU/100, Mullins/16.

volume to account for the use of monthly, daily, and hourly products. Over objections from Staff, CUB, and ICNU, the Commission approved the Company's adjustment, concluding that the record supported the adjustment and it "result[ed] in a more accurate estimate of net power costs."[6]

Q. Is the Company's modeling in this case consistent with the system balancing transaction adjustment approved by the Commission in the 2016 TAM?

A. Yes. In this case, the Company made just one update to the adjustment, updating the underlying historical data to be based on the 48-months ended June 2015 versus the 36-months ended June 2014 used in the 2016 TAM (an update that, as described below, reduced NPC).

Q. Have Staff, CUB and ICNU again objected to the system balancing transaction adjustment in this case?

A. Yes. In approving the system balancing transaction adjustment in the 2016 TAM, the Commission encouraged the parties to "examine this modeling change in more detail in the next TAM cycle."[7] In this case, Staff, CUB, and ICNU have renewed their objections to the Company's adjustment.

Q. Based on their additional review of the system balancing transaction modeling, have the parties raised any new arguments?

A. No. As described in more detail below, the parties' arguments largely reiterate arguments already reviewed and rejected by the Commission. No party provides new evidence or arguments in opposition to the system balancing transaction adjustment or provides an alternative modeling approach.

[6] Order No. 15-394 at 4.
[7] *Id.*

Q. Do the parties dispute that the Company incurs costs that are reflected in the system balancing transaction adjustment?

A. No. Every party recognizes, explicitly or implicitly, that the Company incurs costs to balance its system in real time and every party acknowledges that these real costs are not accounted for in the GRID model.[8] Thus, the only dispute is how best to adjust the Company's power cost modeling to capture these costs.

Q. Has any party proposed an alternative methodology to capture the costs of system balancing?

A. No. The parties agree that there are real costs that are unaccounted for, but no party has proposed an alternative solution. Instead, the parties recommend rejection of the Company's modeling without demonstrating that the NPC forecast is more accurate without it.

Q. Staff and CUB generally recommend that the Company refine its forward price curve to better account for the cost of system balancing transactions.[9] Does the Company disagree with the proposal to refine the forward price curve?

A. Not in concept. The Company is willing to consider this recommendation as a potential long-term solution. But without further review and without specific proposals from the parties, the Company cannot evaluate the benefits and risks of this alternative in this case. Parties have provided no evidence that a TAM forecast incorporating a refined forward price curve would produce an

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[8] Staff/200, Kaufman/3-4; CUB/100, McGovern/28-29; Docket No. UE 296, ICNU/100, Mullins/16.
[9] Staff/200, Kaufman/7; CUB/100, McGovern/30; ICNU/100, Mullins/6.

appreciably different result from that under the current system balancing transaction methodology.

Moreover, even if the Company were able to refine its forward price curve in a way that would eliminate the need for the system balancing transaction adjustment, the modeling moratorium imposed by the Commission in docket UE 296 would preclude introduction of this modeling change in this case.

Q. Please summarize your response to the parties' proposals to eliminate the system balancing transaction adjustment.

A. There is overall agreement that there are real costs related to system balancing transactions that are not otherwise accounted for in the GRID model. After full litigation of the issue in the 2016 TAM, the Commission approved the system balancing transaction adjustment to produce a more accurate NPC forecast. The parties' proposals to undo the system balancing transaction adjustment in this case effectively argue that the Commission should revert to a less accurate NPC forecast because of alleged imperfections in the modeling. But it is clear that, even if the system balancing transaction adjustment could continue to be improved and refined, retaining the adjustment results in a better NPC forecast than eliminating it altogether.

Response to Staff's Position on the System Balancing Transaction Adjustment

Q. Please respond to Staff's objection to the system balancing transaction adjustment claiming that the Company did not fully describe it in testimony.[10]

[10] Staff/200, Kaufman/6.

A. The Company's direct testimony in this case provided an overview of the adjustment and was intended to build on the voluminous record developed in docket UE 296. The Company's testimony here and in docket UE 296 fully and completely explains and justifies the system balancing transaction adjustment. To respond to Staff's claim, however, I will again summarize the adjustment.

Q. Please describe the system balancing transaction adjustment.

A. The adjustment for system balancing transactions has two components: (1) the Company adjusts market prices for purchases and sales, and (2) the Company adds additional volumes which reflect the fact that GRID determines a single transaction volume for each hour whereas the Company must actually balance its system with a combination of monthly, daily, and hourly products.

For the adjusted market prices in GRID, the Company uses the historical differences between the average market prices over each month and actual prices for the Company's day-ahead and real-time balancing transactions in that month, for both purchases and sales. This adjustment creates a more accurate forecast of market prices used for system balancing in the GRID model. Previously, GRID model forecasts only included monthly average prices, and the same prices were used for purchases and sales.[11] The pricing component increases the Company's NPC by $5.4 million.

For the additional volume, the Company calculates the volume that reflects the operational practice of transacting on a monthly basis using standard

[11] Wholesale market prices for the system balancing transactions in GRID are based on an hourly forward price curve that is developed from monthly HLH and LLH prices with hourly scalars applied. These scalars are identical within a given month for each weekday of that month. The prices are input into the model and do not change based on the volume of the system balancing transactions.

25 megawatt (MW) block products, rebalancing on a daily basis using standard 25 MW block products, and finally closing the remaining position on an hourly basis in real-time markets. As designed, the GRID model perfectly balances each hour to the fraction of a megawatt and does not simulate transacting in the market using standard products. The result of the Company's adjustment is to include additional monthly, daily, and hourly transactions, in the form of offsetting sales and purchases representing this balancing process. The Company calculates these volumes outside of the GRID model and prices them to cover the Company's historical average system balancing costs not already captured within the GRID model results. The additional volume component increases the Company's NPC by $3.6 million.

Q. Why did the Company originally propose the system balancing transaction adjustment in docket UE 296?

A. The Company's historical experience demonstrates that it incurs significant expense in the day-ahead and real-time markets to balance its system. As I explained in my testimony in docket UE 296, compared to simply transacting at the monthly average market price the Company incurs a net expense for these balancing transactions. This cost in excess of the average market costs is because of timing: the Company is generally buying during periods when prices are high and selling during periods when prices are low.

This issue is illustrated in Confidential Figure 2 below, which shows actual heavy-load-hour (HLH) prices at the Mid-Columbia (Mid-C) market hub during September 2013, along with the actual volume of the Company's Mid-C purchase and sale transactions that month. The average HLH market price that month was $38 per megawatt-hour (MWh), but during the month the Company paid an average of $43/MWh when it made market purchases and received an average of $29/MWh when it made market sales.

[Begin Confidential]

Confidential Figure 2

[redacted]

[End Confidential]

Without the Company's proposed modeling refinements, the average HLH market price in the GRID 2017 NPC forecast results in Mid-C HLH prices in September 2017 of $31.18/MWh for purchases and $29.93/MWh for sales, compared to an HLH market price of $30.61/MWh. The Company's proposal is intended to more accurately match the purchased power costs and sales revenues in the NPC forecast with actual historical experience.

Q. Staff also claims that the Company's adjustment is flawed because it creates illogical results that require secondary adjustments.[12] How do you respond?

A. Staff's criticism is misplaced. Staff claims that there are certain months in the historical period that are used for the system balancing transaction adjustment where the purchase prices are, on average, less than the sale prices.[13] When this occurs, the Company prevents GRID from taking advantage of the arbitrage opportunities. Staff claims that the fact this secondary adjustment is needed demonstrates that the system balancing transaction adjustment is inappropriate.

On the contrary, if the inputs to the GRID model for a single market showed a purchase price that was less than the sales price, as has occurred historically in limited circumstances, then the GRID model would buy and sell arbitrarily large volumes of power even though, in reality, the transacted volumes would be very limited. Staff appears to agree that this is an "illogical result."[14]

To prevent this "illogical result," when the average monthly sales price exceeds the monthly purchase price in the same market, the Company applies a single price adjustment for both sales and purchases based on the volume-weighted average of the historical sales and purchases. Contrary to Staff's claim, the fact that the system balancing transaction adjustment uses a multi-faceted approach to produce logical results that are consistent with historical data does not mean the adjustment is flawed—it means that the adjustment works.

In addition, any benefits resulting from historical periods with sales prices that were higher than purchase prices are reflected in the Company's additional

[12] Staff/200, Kaufman/6.
[13] Staff/200, Kaufman/6.
[14] Staff/200, Kaufman/6.

volume adjustment, which ensures that the system balancing costs in excess of average market costs in the forecast period match the historical average.

Q. Staff also claims that the system balancing transaction adjustment is unrealistic because it models simultaneous sales and purchase prices even though markets do not actually have two simultaneous prices.[15] How does having two separate market prices in GRID better reflect the Company's operating reality?

A. The separate prices reflect the fact that the Company tends to sell when prices are low and buy when prices are high. Staff does not dispute this fact[16] and in Order No. 15-394, the Commission was "persuaded that short-term purchase prices systematically exceed short-term power sales prices" and that "PacifiCorp has offered a reasonable adjustment to its forward price curve to account for these expected price differences that will result in a more accurate estimate of net power costs."[17]

The separate prices used in the system balancing transaction adjustment are necessary because forecasting the actual, single market price for a particular time period is extremely difficult. There are many contributors to market prices, most of which are related to external factors, in the form of the load and resource positions of other market participants. Because accurately forecasting single market prices is so difficult, the Company has identified the relative cost of historical purchases and historical sales *for the Company* and accounted for the cost impact of these two distinct circumstances. The Company's modeling of a

[15] Staff/200, Kaufman/5.
[16] Staff/200, Kaufman/8-9, 12-13.
[17] Order No. 15-394 at 4.

differential between prices for sales and purchases is also consistent with the modeling used by Idaho Power for many years.[18]

Q. Does the modeling of two separate market prices imply that the Company believes two separate prices are applicable in that hour?

A. No. GRID is designed to make decisions about whether to buy and sell, and how much. The intent of two market prices is to give GRID better signals about what prices are likely to be if it is looking to sell versus if it is looking to buy. The Company does not identify which hours are "buy" hours, and which hours are "sell" hours, because GRID does this automatically. In any hour when GRID is buying, the buy price is the best estimate of the market price, whereas in any hour GRID was selling, the sell price is the best estimate of the market price.

Q. Does the Company's adjustment produce a forecast that more accurately represents the normal power price variation than what is present without the adjustment?

A. Yes. On average, prices are relatively higher in hours when the Company is buying, and lower in hours when the Company is selling, just like in actual operations, as shown in the Company's historical calculations and as found by the

[18] *Re Idaho Power Co. Request for General Rate Revision*, Docket No. UE 167, Order No. 05-871 at 8 (July 28, 2005) (Commission recognized there is "merit in Idaho Power's argument that its power purchases and sales should not be subject to flat prices. As Idaho Power indicated, when its loads are lower at off-peak times, it has excess power supply that it can sell; however, when its loads are higher, at on-peak times, it is short and must buy electricity on the market. Accordingly, we conclude that Idaho Power's net variable power costs should be priced using the April 30, 2004 price curve, on-peak prices for purchases and off-peak prices for sales.") (internal citations omitted); *Re Idaho Power Co. Application for Authority to Implement a Power Cost Adjustment Mechanism for Electric Service to Customers in the State of Oregon*, Docket No. UE 195, Order 08-238, App. A at 3-4 (Apr. 28, 2008).

Commission in docket UE 296. This result was also illustrated in Figure 1 of my direct testimony in this case.[19]

Q. Staff argues that GRID already differentiates market prices into periods of higher and lower prices and therefore the system balancing transaction adjustment is unnecessary.[20] Is this correct?

A. Staff is correct that GRID already includes periods of higher and lower market prices. But this does not mean that the system balancing transaction adjustment is unnecessary, particularly given that Staff agrees that there should be more variation from day-to-day in GRID.

Q. Staff claims that the price adjustment related to system balancing transactions is arbitrary because the magnitude of the adder corresponds to the arbitrary period over which market prices are averaged.[21] How do you respond?

A. The Company calculated its adjustment using a monthly average to correspond to the use of a monthly OFPC. Staff has failed to provide any analysis supporting a superior time period over which to average market prices. Moreover, the system balancing transaction adjustment is consistent with the Company's OFPC, which utilizes monthly HLH and light-load-hour (LLH) granularity. Fundamentally, the forward prices in the GRID model are tied to those monthly HLH/LLH results, even with the inclusion of the system balancing transaction adjustment. The Company believes that its OFPC is the best estimate of the monthly average

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[19] PAC/100, Dickman/18.
[20] Staff/200, Kaufman/3.
[21] Staff/200, Kaufman/4-5.

prices for the 2017 forecast period and no party has disputed the monthly prices in the OFPC or in their use in the GRID model.

Q. Staff further claims that the Company's adjustment does not account for other changes to NPC resulting from system balancing transactions, for example, changes in fuel use corresponding to changes in market prices.[22] Is this a fair criticism?

A. No. First, Staff's claim applies to GRID with or without the system balancing transaction adjustment, and Staff presented no evidence that the Company's overall NPC forecast is more accurate without the adjustment.

Second, Staff's criticism is misplaced. I agree that to the extent the two prices reflected in the system balancing transaction adjustment understate the full range of market price variability, additional impacts to fuel use would be expected. These fuel use impacts, however, would *increase* NPC beyond the level of the historical costs. If market prices are sometimes higher than presently reflected in GRID, more expensive resources would be called upon, such as the combustion turbines or steam units at the Gadsby plant. If market prices are sometimes lower than presently reflected in GRID, lower cost resources would be backed down, potentially even the Company's lowest cost units, Colstrip, Wyodak, and Dave Johnston. Greater dispatch of high-cost resources would raise the average fuel cost. Lesser dispatch of low-cost resources would likewise raise the average fuel cost. In both instances, NPC would be higher. Thus, to the extent that the system balancing transaction adjustment does not account for changes in fuel use, the adjustment understates overall NPC.

[22] Staff/200, Kaufman/12.

Q. Staff also claims that the volume component of the Company's adjustment achieves an arbitrary cost increase with no rational relationship to the GRID forecast.[23] Does the Company's system balancing transaction adjustment produce a forecast that is more correlated with PacifiCorp's load than a forecast without the adjustment?

A. Yes. The GRID model performs a single balancing step with perfect knowledge of a single set of prices, loads, and resources. The volume identified in the Company's system balancing transaction adjustment accounts for three balancing steps (monthly, daily, hourly), with perfect knowledge of loads and resources. In reality prices, market depth, loads, and resources are all uncertain and estimates vary at each step in the process. As a result, the additional balancing volume identified in the Company's volume adjustment understates the volume in question, but it does help to show a more realistic result.

In essence, Staff argues that GRID demonstrates that actual operations, as evidenced by historical transactions, are irrational and fundamentally flawed. The more likely result is that GRID does not sufficiently account for the real constraints faced in the Company's operations, which is why the system balancing transaction adjustment is necessary. The Company has systematically experienced the market price effects captured in the system balancing transaction adjustment over the past several years—a fact that Staff has not disputed with actual analysis.

Q. How do you respond to Staff's contention that the price that is applied to the additional volumes is arbitrary?

[23] Staff/200, Kaufman/10.

A. I disagree that the price is arbitrary. The price that is applied to the additional volumes reflects the normalized cost impact, in excess of transacting at average market prices, of the historical system balancing transactions as a whole. The price is not intended to represent a price per megawatt-hour for individual transactions.

Q. Staff further claims that the adjustment irrationally creates greater monthly and daily balancing transactions even when there are less real-time transactions.[24] Is this correct?

A. No. Staff's conclusion is backwards. As the Company has described, it balances its system using monthly, daily, and hourly transactions. Logically, the required volume of transactions to balance the system in a particular hour depends on all transactions made prior to that hour. So the volume of hourly transactions will depend on the volume of both monthly and daily transactions that have already occurred (along with many other factors including changes in load, resources, etc.). Staff's argument is illogical because it assumes that the need for monthly and daily transactions depends on the volume of hourly transactions. But hourly transactions, by definition, will occur *after* monthly and daily transactions and cannot retroactively impact the need for those monthly and daily transactions.

Q. Has Staff provided any additional explanation for this claim?

A. Yes. During discovery, Staff attempted to justify this position by claiming that "PacifiCorp has not demonstrated in testimony that its actual behavior is consistent with" its claim that it relies on monthly, daily, and hourly transactions

[24] Staff/200, Kaufman/11.

to balance its system.[25] The Company disagrees—in both this case and docket UE 296, the Company provided extensive evidence describing exactly how it balances its system. Indeed, in docket UE 296, the Commission made a specific finding that the "historic GRID modeling understated volumes of transactions because it assumed the volumes of purchases and sales matched exact needs."[26] Further, the Commission agreed to "increase balancing transaction volumes to reflect that the company balances its system with hourly products and 25 megawatt (MW) block monthly and daily products."[27] Staff's testimony does not even refer to this finding from docket UE 296 nor does Staff present any evidence to refute this finding.

Q. Staff claims that some monthly and daily transactions are categorized as hedging or arbitrage transactions and are not, therefore, system balancing transactions.[28] How do you respond to Staff's claim that the system balancing transaction adjustment includes hedging transactions?

A. The Company limited the calculation of its adjustment to transactions with a delivery period of less than one week, as these are necessary to balance the Company's system and cannot be postponed. Thus, the calculation of the system balancing transaction adjustment does not include hedging transactions, contrary to Staff's suggestion. Notably, ICNU made this exact same argument in docket UE 296, which the Commission rejected.

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[25] PAC/407 (Staff Response to PacifiCorp Data Request 2).
[26] Order No. 15-394 at 4.
[27] *Id.*
[28] Staff/200, Kaufman/12.

In response to a data request, Staff identified 3,140 transactions that it characterizes as hedging transactions because the trades were done more than three days in advance.[29] Only 943 of these were less than one week in length and included in the calculation of the system balancing transaction adjustment. All but nine of the identified transactions were done four or five days in advance. Trading several days in advance is necessary and common due to weekends and holidays, and it is incongruous to describe such trades as hedges. An example of one of these transactions was a trade entered on Wednesday, November 23, 2011, for delivery on Monday, November 28, 2011. Due to the Thanksgiving holiday and a weekend, the last trading day for this period was five days earlier. The Company has not assessed the circumstances of each of the nine trades done more than five days in advance, but they have an immaterial impact on the Company's system balancing adjustment.

Q. Does the system balancing transaction adjustment include arbitrage transactions?

A. Yes. The Company purposefully included arbitrage transactions entered at the same time for the same volume and delivery point so that the benefits were included in the historical results. This reduces the cost of system balancing transactions and is realistic because it reflects the historical availability of such opportunities.

[29] PAC/408 (Staff Response to PacifiCorp Data Request 12).

Q. Staff claims that the Company's adjustment is contrary to PacifiCorp's past testimony and past Commission findings that GRID underestimates the volume of market transactions.[30] Is this a reasonable criticism?

A. No. Staff supports this claim by citing to the Commission's order in the 2008 TAM. Staff fails to even mention that ICNU made the exact same argument in docket UE 296 and that the Commission rejected it. Indeed, in Order No. 15-394 the Commission specifically found that PacifiCorp's "historic GRID modeling understated volumes of transactions because it assumed the volumes of purchases and sales matched exact needs."[31] Staff presented no new evidence in this case on which the Commission can change its finding in Order No. 15-394.[32]

Response to CUB's Position on System Balancing Transaction Adjustment

Q. What is the basis for CUB's opposition to the system balancing transaction adjustment?

A. CUB presents several arguments in opposition to the system balancing transaction adjustment, which I will address individually below. CUB's general opposition, however, is based on largely the same arguments that the Commission already addressed and rejected in docket UE 296. Moreover, while CUB takes issues

[30] Staff/200, Kaufman/5.
[31] Order No. 15-394 at 4.
[32] In docket UE 296, the Company distinguished the evidence and findings in the 2008 TAM. In docket UE 296, ICNU's argument focused on the treatment of bookouts, which are transactions that are equal and offsetting in terms of volume, delivery period, and location. Both in docket UE 296 and in docket UE 245, however, the Company made the same argument—comparisons between transaction levels in actual and forecast NPC must include or exclude bookout transactions on both sides to avoid apples-to-oranges comparisons. In docket UE 296, the Company demonstrated that its modeled volumes, including the additional system balancing transactions that are proxies for bookouts, correspond to historical transaction volumes including bookouts. ICNU's argument that the Company overstates transaction volumes is solely a function of ICNU omitting bookout transaction volumes from historical levels. In docket UE 245, ICNU and CUB argued that all transactions, even bookouts, must be accounted for when modeling NPC transaction levels. The Company's adjustment does just that by including additional system balancing transactions, *i.e.*, proxies for bookouts, that are systematically incurring costs.

with the system balancing transaction adjustment, like Staff, CUB acknowledges that the adjustment captures real costs that are not otherwise included in the Company's NPC forecast.[33] And, like Staff, CUB fails to present any alternative methodology to capture these costs. Overall, CUB provides no justification to reject the system balancing transaction adjustment.

Q. CUB claims that the Company's adjustment violates the modeling moratorium from docket UE 296 because the adjustment now relies on four years of historical data instead of three.[34] Do you agree that the use of four years of historical data represents a modeling change that is prohibited by Order No. 15-394?

A. No. In docket UE 296, the Company relied on three years of historical data to calculate the system balancing transaction adjustment because that was the only data available at the time the Company's case was prepared. In this case, the Company had access to four years of historical data, and using a four-year period was consistent with the historical period used to normalize other components of NPC, like outage rates.

Q. Does the Company object to limiting the calculation of the system balancing transaction adjustment to three years of historical data?

A. No. Notably, in this case, the system balancing transaction adjustment increases by approximately $1.1 million with the use of only three years of historical data. In response to CUB's concerns about the uncertainty created by changing the underlying historical time horizon, the Company proposes using three years of

[33] CUB/100, McGovern/28-29.
[34] CUB/100, McGovern/25-26.

data in future TAMs, but foregoing the NPC increase resulting from implementation of CUB's recommendation here. Regardless of whether the adjustment is based on three or four years of historical data, it still results in a more accurate forecast of NPC.

Q. CUB claims that the Company's participation in the EIM renders historical market transactional data less relevant.[35] Is this a fair criticism of the system balancing transaction adjustment?

A. No. The implication of CUB's argument is that the participation in the EIM has reduced the Company's need to incur the system balancing costs captured by the adjustment. The historical data, however, says otherwise. The system balancing transaction costs in calendar year 2015, the first full year of EIM data, were actually higher than the 48-month average.

Q. Why doesn't the Company's participation in the EIM reduce the Company's system balancing costs?

A. Participation in the EIM requires the Company to submit balanced base schedules 55 minutes prior to the hour. Thus, under the EIM, market purchases and sales must be executed at least 60 minutes in advance in order for the Company to present a balanced schedule at the 55-minute mark. Before the Company's participation in EIM, the Company was required to submit balanced base schedules 20 minutes before the hour and could therefore transact up to around 30 minutes before the hour. Because the EIM requires PacifiCorp to balance its system 60 minutes in advance, instead of 30 minutes, there is more uncertainty, and both the Company and its counterparties may be less willing to transact. If

[35] CUB/100, McGovern/26-27.

parties are less willing to transact, there will be higher prices for purchases because counterparties do not want to part with resources that might be needed. 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.

Q. CUB raises concerns about the use of historical data when forecast NPC is meant to be weather normalized.[36] Is this a valid criticism of the system balancing transaction adjustment?

A. No. CUB made the same argument in docket UE 296, which was specifically rejected by the Commission. In Order No. 15-394, the Commission found that "PacifiCorp's use of three years of data is sufficient to smooth out variations to generate a reasonable estimate of expected spot price differentials."[37] Arguably, the use of four years of historical data as applied in this case would further address concerns over normalization.

Q. Why is it reasonable to use historical prices to calculate the system balancing transaction adjustment?

A. As explained thoroughly in docket UE 296, to the extent the Company's purchase prices and sales prices in a month were relatively high, the overall average market prices would have also been high. It is only the difference between the historical monthly average price and the prices at which the Company transacted that is

[36] CUB/100, McGovern/28.
[37] Order No. 15-394 at 4.

considered in the Company's adjustment to system balancing transactions in the TAM.

Response to ICNU's Position on the System Balancing Transaction Adjustment

Q. What is the basis for ICNU's opposition to the Company's adjustment?

A. ICNU renews several arguments from docket UE 296. First, ICNU claims that the volume component of the adjustment is unnecessary because the "alleged additional volumes are not supported by the historical data—other than through the inclusion of book-out transactions."[38] This exact argument was made in docket UE 296, and was rejected by the Commission. ICNU provides nothing in the way of new evidence or argument on this point.

Q. What is ICNU's second argument in opposition to the system balancing transaction adjustment?

A. ICNU implies that the adjustment is a bid-ask spread and that modeling market spreads does not address the underlying problem the Company claims to be solving.[39] In docket UE 296, the Commission also specifically rejected the argument that the adjustment was modeling a bid-ask spread.[40] ICNU argues that a better approach would be to model greater within-month price variability.[41] But ICNU's recommendation to remove the Company's adjustment results in less price variability, so ICNU's overall recommendation is logically inconsistent with its testimony on this point.

Q. What is ICNU's third argument in opposition to the Company's adjustment?

[38] ICNU/100, Mullins/6.
[39] ICNU/100, Mullins/6.
[40] Order No. 15-394 at 4.
[41] ICNU/100, Mullins/6.

A. Citing its testimony in docket UE 296, ICNU argues that the adjustment relies on non-normalized historical data.[42] As noted above, the Commission rejected this exact argument in docket UE 296 and ICNU has presented no additional evidence in this case.

Q. What is ICNU's fourth argument in opposition to the Company's adjustment?

A. ICNU recommends that if the Commission again approves the system balancing transaction adjustment, the methodology should be changed to better account for day-ahead integration costs.[43] ICNU contends that day-ahead integration costs are included in the system balancing transaction costs and should therefore be removed from the NPC calculation.

Q. Is this a new argument from ICNU?

A. No. ICNU presented the same argument in docket UE 296 when it argued that the Company's inter-hour wind and load integration charges already capture the costs associated with balancing the Company's system.[44] Although in this case ICNU describes the integration costs as *intra*-hour, rather than *inter*-hour, the adjustment is the same.

Q. How did the Commission resolve ICNU's recommendation in docket UE 296?

A. The Commission did not specifically address this argument in its order, but in rejecting all challenges to the system balancing transaction adjustment, the Commission implicitly rejected ICNU's argument.

[42] ICNU/100, Mullins/5.
[43] ICNU/100, Mullins/3-4.
[44] Docket UE 296, ICNU/100, Mullins/17-18.

Q. Has ICNU presented any new evidence to support its recommendation to eliminate the day-ahead integration charges?

A. No.

Q. How are the inter-hour integration costs determined?

A. These values were calculated in the Company's 2014 Wind Integration Study. In that study, system costs were calculated for two different scenarios. In the first scenario, gas plants were committed based on the actual load forecast, which represents the optimal commitment. In the second scenario, gas plants were committed based on the day-ahead load forecast, which represents the commitment decision in the Company's actual operations, where gas must be nominated in advance, and startup and shutdown constraints limit gas plant flexibility. The second scenario has higher costs, because the optimal commitment decision for the forecasted load may not be optimal for the actual load. Analogous studies were prepared to measure the incremental impact of forecasted and actual wind.

Q. Does the Company's GRID forecast continue to over-optimize the natural gas plant commitment?

A. Yes. The Company's natural gas plant screening process optimizes unit commitment based on a known forecast of wind and load, as well as outages, prices, and other inputs. These inputs do not change between the commitment decision and actual unit dispatch, so the Company's forecast does not otherwise account for the uncertainty between the forecast and actual operation.

The studies on which the inter-hour integration costs are based use the same hourly price forecasts previously employed by the Company, and are uniform across each month. The integration costs thus only measure the cost associated with the achievable optimization of gas plant commitment based on forecasted information, rather than perfect optimization with perfect foresight of system requirements. ICNU's attempt to discredit the Company's current system balancing proposal by referencing these costs is baseless.

Q. What is ICNU's final objection to the Company's adjustment?

A. ICNU claims generally that decreasing NPC in recent years mitigates the need for this adjustment.[45] The historical data underlying the system balancing transaction adjustment does not support the correlation ICNU suggests between declining NPC and system balancing costs. Furthermore, the Company's system balancing transaction adjustment is based on historical evidence of costs that the GRID model does not otherwise reflect. This systematic understatement of actual costs has contributed to the Company's under recovery of NPC in Oregon. Indeed, in 2015, the Company's actual NPC was the lowest level since 2012. Yet, the Company still under-recovered its NPC by nearly $20 million. The 2015 TAM forecast did not include the system balancing adjustment.

Coal Plant Dispatch

Q. Staff and CUB address the dispatch of coal plants in the TAM and recommend different adjustments to remove the impact of take-or-pay

[45] ICNU/100, Mullins/7.

provisions in the Company's coal contracts.[46] **What are take-or-pay provisions?**

A. As explained in greater detail by Company witness Mr. Ralston, coal supply contracts typically include a so-called "take-or-pay" provision that mandates a minimum volume of coal that must be delivered in a given period. Thus, even if a coal plant is dispatched such that it does not require the minimum volume of coal required by the contract, the Company must still take delivery of the minimum volume or pay the equivalent cost.

Q. Please explain how the GRID model determines the dispatch of coal plants.

A. GRID dispatches coal plants based on the incremental cost of coal—the cost of the next increment of coal that can be burned to generate electricity. If the cost to generate is less than the market price of electricity, the coal plant is dispatched up. Once the total generation from each coal plant is known, the total cost of the coal (including any fixed charges) is spread over the total coal volume.

Q. How are take-or-pay provisions modeled in GRID?

A. GRID does not internally account for minimum coal requirements and therefore modeling the impact of take-or-pay provisions requires additional steps. If a coal plant is dispatched such that it would not meet the minimum coal volume required by the contract, then the incremental cost of the coal is zero until the minimum delivery is met. Once the minimum delivery is met, the next quantity of coal can be supplied at a certain incremental price, and so forth. However, the incremental coal cost input to the GRID model is a single value and multiple tiers of prices are not recognized. The incremental cost input to the GRID model at times must be

[46] *See* Staff/200, Kaufman/24; CUB/100, McGovern/7-9.

an interpolated value to increase the generation at that plant to meet the minimum coal requirements, or recognize contractual volume limits, thereby minimizing overall NPC.

In the current filing, and in past TAM filings, the Company applied dispatch costs for coal on an annual basis, which is aligned with both the forecast period and annual coal supply requirements in the underlying contracts. Because incremental costs are applied on an annual basis, GRID will dispatch one coal unit over another in all hours. A small change in price, if it affects the ranking of two units, can result in large changes in volume as GRID dispatches the unit with lower incremental cost first in all hours. This interaction between plants makes finding the optimal dispatch price for the coal units an iterative modeling process.

Q. Can you illustrate how incremental coal costs are reflected in the GRID model?

A. Yes. Confidential Figure 3, shows the incremental cost of coal at the Jim Bridger plant as a function of volume, as well as the incremental costs for Jim Bridger modeled in GRID, both as reflected in the Company's Initial Filing. This data was also provided to parties in response to ICNU Data Request 8.

[Begin Confidential]

Confidential Figure 3

[redacted]

[End Confidential]

Q. What does the incremental coal supply in Confidential Figure 3 represent?

A. The incremental coal supply line represents the incremental cost of coal for a given volume. The vertical portion of the line in Confidential Figure 3 marks the total coal volume available from the BCC mine plan reflected in the Initial Filing plus the minimum coal volume in the Black Butte contract for 2017. This is the minimum annual coal volume for the Jim Bridger plant. Volumes to the right of the vertical line represent the marginal cost of additional coal supplied under the Black Butte contract. For incremental volumes to the right of the vertical line, the Black Butte contract cost is applicable. For volumes left of the vertical line, the take-or-pay clause of the Black Butte contract is applicable, so the incremental cost is zero.

Q. What does the point reflecting the GRID modeling result in Confidential Figure 3 represent?

A. The GRID run from the Initial Filing used a single incremental cost of [Begin Confidential] [redacted] [End Confidential] for the Jim Bridger plant, and resulted in volumes that were approximately [Begin Confidential] [redacted] [End Confidential] the minimum annual coal volume. The incremental price input to GRID is a composite that reflects the demand for coal at the Jim Bridger plant with the minimum volume priced at zero and additional volume priced at the incremental cost of the Black Butte contract.

If the Jim Bridger plant's dispatch was based on an incremental cost of zero, the annual take would be much higher than the minimum annual coal volume. On the other hand, if the Jim Bridger plant's dispatch was based on the Black Butte incremental cost, the annual take would be well below the minimum annual coal volume. Neither of these results is realistic as they are not located on the Jim Bridger plant coal supply curve. To achieve a result that is closer to the supply curve, the Company uses a dispatch price for the Jim Bridger plant in GRID that is between these two bookends. As the dispatch price increases from zero, there are more hours in which market purchases or dispatching other coal plants becomes cheaper than generating with the Jim Bridger plant.

Q. Have the coal supply and demand at the Jim Bridger plant changed in the Company's Reply Update?

A. Yes. The incremental coal supply curve from the Reply Update is shown in Confidential Figure 4. [Begin Confidential] [redacted]

[redacted] [End Confidential] Details on these supply options are provided in the testimony of Mr. Ralston. As shown in Confidential Figure 4, in the Reply Update the GRID model [Begin Confidential] [redacted]

Confidential Figure 4

[redacted]

[End Confidential]

Q. Are adjusted coal dispatch prices applicable only for plants with minimum take?

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[47] As described by Mr. Ralston, the Jim Bridger plant has the physical infrastructure to accept delivery of only limited volumes of PRB coal. The update discussed here is limited to those volumes. To be clear, the fact that the plant can accept limited PRB deliveries does not imply that PRB coal could entirely replace BCC coal in 2017, as explained by Mr. Ralston.

A. No. As shown in Confidential Figure 4, vertical lines in coal supply occur whenever there is a step change in incremental costs between one supply tier (identified in a supply contract or other coal source) and another. Whenever the dispatch at the lower price exceeds the volume available at that price, and the dispatch at the higher price drops back into the volume applicable to the lower price, an adjusted coal dispatch price is necessary. This has always been the case with the coal plant dispatch in the GRID model.

Q. Has the Company explored other alternatives that will better align coal dispatch prices and volumes in GRID?

A. Yes. Rather than using an annual coal price, the Company believes an alternative method could use incremental coal price that are input into the model on an hourly basis. The finer granularity allowed by hourly adjustments could bring the results much closer to the targeted levels.

Q. How would the alternative method work?

A. The alternative method would be tied to the specific pricing tiers for each coal plant. In reality, there is a hard shift in price between coal burned in one price tier and coal from the next supply tier. If too much coal is burned at the price for the lower tier, the real coal cost in some hours is the next supply price. To align the availability of coal with the Company's system costs, the hours with the lowest market prices would be assigned a coal cost at the higher tier price. This reduces the output of the plant in those hours (if it wasn't already reduced) and brings the plant closer to its targeted volume.

Q. Have you implemented this alternative method in the Reply Update?

A. No. Due to the modeling moratorium, the Company has not proposed to alter the method for dispatching the coal plants, but would be willing to support the change in the 2018 TAM.

Q. How many coal plants did the Company adjust to meet contractual minimum take requirements in its Initial Filing?

A. In my direct testimony, I identified four plants that the Company dispatched to meet minimum take requirements: [Begin Confidential] [redacted] [End Confidential]. I also indicated that if market prices declined further, it was possible that the Company would dispatch other coal plants in this manner.

Q. Did the natural gas and electric market prices in the Company's Reply Update require additional adjustments to the dispatch price of any other coal plants in order to meet minimum-take requirements?

A. No. In fact, prices for natural gas and electricity in the June 30, 2016, OFPC were higher than the March 3, 2016, OFPC used in the Initial Filing. Based on the June OFPC, only the [Begin Confidential] [redacted] [End Confidential] plants required an adjustment to achieve minimum contract requirements in the Reply Update.

Q. Please describe Staff's proposed adjustment.

A. Staff argues that the Company's modeling of take-or-pay provisions is a new modeling change that is prohibited by the Commission's moratorium imposed in the 2016 TAM.[48] Based on this reasoning, Staff proposes to disallow the impact of any plant not meeting the minimum take provisions of a contract, and to strictly

[48] Staff/200, Kaufman/22-23.

adhere to the incremental contract cost at each plant even if it means minimum volumes are not met. In effect, Staff proposes that the Commission simply ignore contract minimums and establish the Company's NPC as if those minimums did not exist. Staff provided a preliminary estimate of the impact of its adjustment as a decrease to NPC of $16.3 million on a total company basis.[49]

Q. Is it reasonable to simply ignore contract minimums for purposes of NPC modeling?

A. No. As Staff acknowledges, "contract minimums have a real impact on power costs."[50] The Commission has been clear that the purpose of the TAM is to produce the best forecast of actual NPC.[51] Intentionally excluding costs that Staff admits "have a real impact," is contrary to this purpose.

Q. Is the Company's treatment of minimum coal requirements new to the 2017 TAM?

A. No. In previous cases, the Company has had to adjust the incremental dispatch price of coal to ensure minimum requirements were met, just as in the Initial Filing. In docket UE 287, the incremental fuel cost of the [Begin Confidential] [redacted] [End Confidential] plant was set at a level below its incremental contract cost to increase the volume used by the plant above the minimum take volume. In docket UE 296, the incremental costs of both [Begin Confidential] [redacted] [End Confidential] were set at approximately zero (the lowest level allowed by GRID), again to accurately reflect the terms of the coal supply agreements for these plants. As described earlier, the method used to model the

[49] PAC/409 (Staff Response to PacifiCorp Data Request 4).
[50] Staff/200, Kaufman/25.
[51] Order No. 12-409 at 7 (Oct. 29, 2012).

incremental price for coal plants has not changed since the GRID model was developed. The Company's approach in this case is not a prohibited modeling change, which is Staff's primary basis for its adjustment.

Q. Did the adjustment to the dispatch price impact more plants this year than in the past?

A. Yes. Coal plants have traditionally been the lowest cost thermal generation and therefore have generally met their minimum volume requirements in GRID. But market developments over the last year, including historically low market prices for natural gas and electricity, have increasingly caused other sources of electricity to displace coal generation. When coal plants are dispatched less it becomes more likely that they may not meet their minimum take requirements in GRID, which requires the adjustments discussed above.

Q. Does Staff provide any additional basis for simply ignoring the costs of contract minimums?

A. Yes. Staff argues that the coal contracts with the take-or-pay provisions "may" be imprudent because parties have previously expressed concern over the execution of long-term coal supply contracts.[52] Importantly, however, Staff clarified in discovery that it is not actually claiming that any of the Company's contracts are imprudent.[53] Thus, Staff has not presented any basis on which to ignore these costs based on a finding of imprudence.

Q. Has the Company demonstrated the prudence of contracts with must-take requirements?

[52] Staff/200, Kaufman/24.
[53] Because Mr. Ralston's testimony also addresses this issue, Staff's data response clarifying its position is attached to his testimony at PAC/502.

A. Yes. Mr. Ralston's reply testimony addresses the prudence of these contracts.

Q. Staff also argues that the Company's approach to modeling take-or-pay requirements is inexact and ad hoc because it does not account for the optionality provided by plant storage capacity.[54] Is this a reasonable basis to simply ignore the costs of minimum coal requirements?

A. No. Staff failed to provide any actual proposal or refinement of the Company's approach or indicate how plant storage capacity could have been utilized to avoid the minimum contract adjustment made in this case. It is unreasonable to simply ignore these very real costs just because Staff believes there may be a better way to model them. In addition, Mr. Ralston's testimony discusses the relationship between coal storage and minimum contract requirements and demonstrates the prudence of the Company's approach to managing its plant storage capacity.

Q. Does Staff acknowledge that ignoring these costs may harm the Company?

A. Yes, but Staff argues that intentionally omitting these costs from the TAM is acceptable because PacifiCorp can recover these costs through the PCAM, if the contracts are found to be prudent.[55] Staff argues for exclusion of costs from the TAM to allow an additional year for Staff to continue its analysis on the basis that costs found to be prudent could be recovered through the PCAM. However, the design of the PCAM as approved by the Commission includes significant deadbands and sharing bands which would not allow recovery of prudent costs if they are completely excluded from the TAM filing that determines the basis for later PCAM true-ups.

[54] Staff/200, Kaufman/24.
[55] Staff/200, Kaufman/25-26.

Moreover, Staff's position here is undermined by its position in docket UM 1662, filed in September 2015, that the utilities should improve the modeling of NPC in base rates, rather than relying on the PCAM for cost recovery:

> Staff recommends the utilities work on developing improved generation production forecasting methodologies to address their risk to under-collect [NPC]. The PCAMs allow each company to recover in rates 100% of the utilities' forecasted costs if the forecasts are accurate and correctly reflect actual costs. It is when the forecast of power costs is in error that the company under-collects. Therefore, improving the accuracy of forecasts will limit the potential that utilities will not fully recover their power costs.[56]

Q. What adjustment did CUB propose in its testimony?

A. CUB argues that the impact of any coal contact with a take-or-pay clause that was entered into since the 2013 IRP (*i.e.*, 2015 or beyond) should be disallowed. Specifically, CUB recommended that the take-or-pay contracts for the Huntington, Jim Bridger, Dave Johnston, and Naughton plants be disallowed and the GRID model be re-run with the minimum of either the market cost of coal or the contract price input as the incremental cost of coal.[57] CUB did not quantify the impact of its proposed adjustment.

Q. Does CUB's adjustment have merit?

A. No, for two reasons. First, CUB's adjustment is inapplicable because none of the Company's coal contracts executed since the 2013 IRP were adjusted in this case to account for the minimum take requirements. Thus, the value of CUB's

[56] *Re Portland General Electric Company and PacifiCorp Request for Generic Power Cost Adjustment Mechanism Investigation*, Docket No. UM 1662, Staff's Prehearing Brief at 8 (Sept. 16, 2015).
[57] PAC/410 (CUB Response to PacifiCorp Data Request 1).

adjustment is zero. Second, Mr. Ralston rebuts CUB's argument that coal supply agreements are imprudent for including take-or-pay provisions.

EIM Benefits – General

Q. In the Initial Filing, how did the Company model the benefits resulting from its participation in the EIM?

A. As I described in my direct testimony, the Company's forecast of EIM benefits in the Initial Filing was based on actual results from January 2015 through December 2015. Consistent with the 2016 TAM, the Company's Initial Filing included benefits associated with inter-regional dispatch, which result from transactions between PacifiCorp and the CAISO, and flexibility reserve benefits, which result from a reduced regulating reserve requirement modeled in GRID. These benefits are in addition to the optimized dispatch of the Company's generation within its balancing authority areas (BAA) (*i.e.*, intra-regional dispatch), which can now be achieved in actual operation and which has always been reflected in the GRID model.

Q. Is the Company's calculation of the EIM benefits in the 2017 TAM more refined than in the 2016 TAM?

A. Yes. First, the Company utilized a full year of historical results, as compared to the 10 months of actual results available in the 2016 TAM.[58] Second, the Company refined the calculation of inter-regional dispatch benefits to identify the cost of specific incremental resources that could have facilitated transfers in each interval of the historical period. Generally, the benefit of EIM exports is equal to

[58] In the 2016 TAM, the Company's modeling used actual results from December 2014 through September 2015, which were the most up-to-date results available at that time.

the difference between the revenue received less the expense of generation assumed to supply the transfer. The benefit of EIM imports is equal to the import expense less the avoided expense of the generation that would have otherwise been dispatched. The refined calculation includes a more accurate production cost, resulting in a more accurate calculation of inter-regional benefits.

Q. Has the Company updated EIM benefits and costs in its Reply Update?

A. Yes. The EIM benefits in the Company's Initial Filing were derived from actual results from the participation of the Company and the CAISO in EIM, and expected results from the participation of NVE, Puget Sound Energy (PSE), Arizona Public Service (APS), and Portland General Electric (PGE). NVE began participating in EIM in December 2015, and the Company now has six months of actual results reflecting the expanded EIM footprint encompassing the Company, the CAISO, and NVE. To reflect the best information available for the expanded EIM footprint, the Company has based the EIM inter-regional transfer benefits in its Reply Update on the twelve months ending May 2016, with annualizing adjustments to account for the impact of NVE participation. Annualizing the results over a twelve month historical period captures the expected seasonal variation in EIM benefits. The specific annualizing adjustments are as follows:

- The December 2015 through May 2016 results for PACE-NVE imports and exports cover most of the October through May "other" season developed in the 2016 TAM to capture the seasonality of EIM benefits. Therefore the average import and export margin from this period is used for the "other" months not covered by the available data. Because

PacifiCorp and NVE operate the paths interconnecting their transmission systems EIM has greater flexibility to determine the transfers over those paths relative to the transfers between PACW and the CAISO over a path operated by BPA. For instance, all un-scheduled transmission capacity between PACE and NVE becomes available to EIM, including counterflows offsetting the hourly schedules on reserved capacity across the path. This is not the case between PACW and the CAISO. In light of this distinction, the margin on imports and exports between PACE and NVE is calculated as a monthly average, rather than as a function of transmission utilization.

- The available PACE-NVE import and export data does not include any summer months. To estimate the benefits during these months, the Company compared the PACW-CAISO inter-regional transfer margin in the summer to that in “other" months. PACW-CAISO import margin was 54 percent lower in the summer, while the export margin was 103 percent higher. These same percentages have been used to adjust the average PACE-NVE import and export margin during “other” months to levels appropriate to the summer season.
- While the Company has PACW-CAISO import and export data for the full twelve-month history, six of those months did not include NVE participation in EIM, including the entire summer period. Transfers to the CAISO and NVE can both rely on PACE resources. While NVE participation has increased the Company overall inter-regional transfer

margin, when the Company transfers to NVE it may be forgoing lower value transfers to the CAISO. This is evident by comparing the historical results for January through May 2015 to those for January through May 2016, as the Company's PACW-CAISO import and export margins declined by 32 percent and 53 percent, respectively. The PACW-CAISO export margin continues to be expressed as a function of the transmission available for EIM exports, and the Company has refreshed the historical transmission available based on a recent extract from the CAISO's public database.

- The GHG component of the export margin has been updated to include results through May 2016, as well as for prior period adjustments resulting from the CAISO's nine month settlement statements. Because this component is not specifically tied to exports to NVE or the CAISO, it has been included as a separate line item in the results.

Q. What is the total level of EIM benefits and costs now included in the 2017 TAM?

A. The Company's Reply Update includes approximately $23.7 million in total company EIM benefits for inter-regional dispatch and reduced flexibility reserves. Table 2 below compares the total EIM benefits and costs in the Initial Filing and the Reply Update on a total company basis.

Table 2
Total-Company EIM-Related Benefits and Costs

$ millions	**2017 TAM - Direct**	**2017 TAM - Reply**
Inter-regional dispatch - Exports	$10.2	$13.9
Inter-regional dispatch - Imports	$1.2	$5.3
Flexibility Reserves	$2.6	$4.5
Test-period EIM benefits	**$13.9**	**$23.7**
Test-period EIM costs	**$6.4**	**$6.2**

Q. Did parties support the Company's approach to modeling EIM dispatch benefits in the Initial Filing?

A. Not entirely. Staff and CUB both proposed adjustments to reduce NPC for intra-regional EIM dispatch benefits. In addition, Staff and CUB each raised separate issues related to the calculation of inter-regional EIM dispatch benefits that they believe need to be addressed or changed. I address each of these below. ICNU did not address EIM benefits in its Opening Testimony.

Q. CUB claims that customers were misled when PacifiCorp entered the EIM, because the benefits are not as high as expected.[59] Do you agree?

A. Absolutely not. CUB claims that EIM benefits are "barely exceeding ongoing costs" and that the benefits "are expected to remain trivial."[60] On the contrary, as noted above, the Company's Reply Update includes $23.7 million of EIM benefits on a total company basis, which is hardly trivial. Moreover, the benefits in this year's TAM are higher than the amount reflected in last year's TAM.

Q. Have Staff and CUB made any general recommendations relating to the modeling of EIM benefits?

[59] CUB/100, McGovern/19-20.
[60] CUB/100, McGovern/20.

A. Yes. Staff recommends a generic investigation into the calculation of EIM benefits, in light of the expected participation of PGE and Idaho Power in the market.[61] CUB recommends that Staff audit the Company's EIM results.[62]

Q. Does the Company object to either recommendation?

A. No. The Company does not object to Staff's proposal for a generic investigation, as long as parties understand that the differences between the operational practices and NPC modeling for the utilities participating in the EIM may not allow for a one-size-fits-all approach. The Company also has no objection to a Staff audit of EIM accounting practices, costs, and benefits, as recommended by CUB.

EIM Benefits – Intra-Regional Benefits

Q. How does the Company reflect the intra-regional benefits resulting from its participation in the EIM?

A. The Company does not include an incremental reduction in its overall NPC calculation to account for intra-regional benefits. The Company's test period NPC are developed using the GRID model, which assumes perfectly efficient operations. Thus, in every hour, the lowest cost resources will be dispatched, subject to transmission constraints. In addition, the Company's gas plant "screening" process optimizes the commitment of each gas unit based on its actual contribution to system costs, accounting for the value at the point of delivery, rather than based on prices at a potentially distant regional market point. Therefore, the Company's NPC already incorporates intra-regional dispatch

[61] Staff/100, Crider/16-17.
[62] CUB/100, McGovern/21.

savings compared to the Company's actual operations. While the Company will experience intra-regional benefits from EIM in its actual operations, those benefits will only bring actual costs closer to the ideal dispatch calculated in the GRID model.

Q. Is the Company's approach in this case the same as last year's TAM?

A. Yes. In docket UE 296, no party challenged the calculation of the intra-regional dispatch benefits and the Commission accepted the Company's forecast of EIM benefits.[63]

Q. Please describe the adjustments Staff and CUB have proposed for intra-regional dispatch benefits.

A. Staff and CUB each propose to reduce NPC by including incremental intra-regional dispatch benefits based on the difference between the total historical benefits calculated by the CAISO (reported on a quarterly basis since EIM began operations) and the total EIM benefits included by the Company in the TAM filing.

Staff proposes that the Company quantify the intra-regional benefits that Staff claims are not included in GRID. If the Company does not quantify the benefits, then Staff calculates an intra-regional benefit by subtracting the EIM benefits already deducted from the TAM (*i.e.* inter-regional and flexibility reserve benefits) from the total benefits reported by the CAISO during calendar year 2015, which reduces NPC by $3.1 million.[64]

CUB proposes a similar adjustment but uses the total benefits reported by

[63] Order No. 15-394 at 8.
[64] Staff/100, Crider/17-18.

the CAISO for the four quarters ended March 2016. CUB's adjustment reduces NPC by $7.1 million.

Q. Is there a calculation error in CUB's proposed adjustment?

A. Yes. CUB's original testimony mistakenly compared the CAISO-reported EIM benefits to the $6.4 million of total company EIM *costs* included the initial TAM filing rather than the $13.9 million of total company EIM *benefits* included in the TAM. On July 21, 2017, CUB filed an errata to its Opening Testimony correcting this error. This reduces CUB's adjustment to $4.9 million—a correction not expressly noted in CUB's errata filing.

Q. What is the basis for Staff's proposed adjustment?

A. Generally, Staff claims that the Company's TAM filings do not reflect the same level of EIM benefits that have been calculated by the CAISO. Staff reasons that the difference between these amounts reflects intra-regional benefits that are not captured in the GRID model.[65]

Q. How does the CAISO calculate EIM benefits for PacifiCorp?

A. To calculate the benefits achieved by the EIM, the CAISO compares the actual EIM dispatch results to a counterfactual scenario that estimates the cost of serving load imbalance as if EIM did not exist. To calculate EIM benefits for PacifiCorp, the CAISO's counterfactual scenario is built to mimic the more manual dispatch process used in actual operations prior to participation in the EIM. The difference between actual EIM results and the counterfactual scenario captures all of the benefits of EIM participation, including intra-regional dispatch savings (optimizing the resources in PacifiCorp's two BAAs), inter-regional dispatch

[65] Staff/100, Crider/11.

savings (transacting with other EIM participants), and flexibility reserve savings (reduced reserves due to diversity across the EIM footprint).

Q. How does Staff conclude that there are additional intra-regional dispatch benefits that are not captured in GRID?

A. Staff cites a CAISO technical bulletin produced on August 28, 2014, and testifies that the counterfactual scenario is "an optimized production cost model, identical to the modeling used for the EIM solution except that EIM transfers are not allowed."[66] Staff concludes that if the counterfactual scenario and GRID are both optimized dispatch solutions, then they are functionally identical and the difference in the EIM benefits calculated by the CAISO and PacifiCorp reflect the intra-regional benefits that are not captured by GRID.[67]

Q. Is Staff's understanding of the CAISO's counterfactual scenario accurate?

A. No. Contrary to Staff's understanding, unlike GRID, the CAISO's counterfactual scenario is not a perfectly optimized solution. In the August 2014 technical bulletin relied on by Staff, the CAISO stated that it intended to produce the counterfactual scenario using the "EIM market clearing engine," but with several modifications intended to mimic pre-EIM conditions for PacifiCorp.[68] The CAISO's modifications included: (1) limiting the pool of resources that can respond to imbalances based on the resources that would have been used pre-EIM; and (2) fixing the dispatch of all other resources at the base schedule submitted by the Company and not allowing a re-dispatch among these

[66] Staff/100, Crider/10.
[67] Staff/100, Crider/11.
[68] PAC/411 (CAISO Technical Bulletin, "Quantifying the Benefits of Participating in EIM," at 5, August 28, 2014).

resources.[69] The end result is that changes in load relative to the base schedule were "relieved by the most physically effective resources, *not by the most economic resources*."[70]

In February 2016, the CAISO updated its explanation of the method used to calculate the realized EIM benefits.[71] In that document, the CAISO appears to have simplified the calculation, no longer utilizing the EIM market clearing engine, but simply calculating the cost of meeting load imbalance in each interval using a limited pool of dispatchable units if that is how the utility operated pre-EIM. Rather than a full model dispatch, the CAISO's counterfactual scenario is now the result of calculating the load imbalance for each BAA and meeting that imbalance with a predetermined stack of resources.[72] No other resources are changed from the base schedule submitted by the utility. Thus, the counterfactual scenario is clearly not a fully optimized economic dispatch solution like the GRID model.

Q. Staff claims that the NPC benefits in this case are far less than those expected by E3 and the CAISO.[73] How do you respond?

A. Staff notes that the EIM benefits included in the Initial Filing were $13.9 million total company, while the CAISO reported actual savings of $26.2 million for calendar year 2015, and the E3 study indicated even greater potential benefits.[74] Staff's comparison is inapt, however, because Staff compares the reductions to the TAM NPC for inter-regional dispatch and flexibility reserve benefits to the

[69] *Id.*
[70] *Id.* at 6 (emphasis added).
[71] Staff/108.
[72] *Id.* at 4.
[73] Staff/100, Crider/7-10.
[74] Staff/100, Crider/8.

total benefits achieved, which include intra-regional dispatch savings already reflected in GRID.

Q. Is there any other evidence confirming PacifiCorp's explanation of the intra-regional benefit calculation?

A. Yes. The results of NVE's participation in the EIM provide additional evidence that the intra-regional benefits are captured in GRID and that EIM helps bring actual operations into alignment with the perfect optimization used in the GRID model. Unlike PacifiCorp, prior to joining EIM, NVE already utilized a computerized security constrained dispatch model to dispatch its resources in actual operations. Thus, its actual operations were already optimized prior to joining the EIM. In the CAISO's quarterly EIM benefit report for the first quarter of 2016, it states that the benefits realized by NVE's participation are mainly inter-regional transfer benefits. The report states that this "is attributed to NVE's optimization of its base schedules prior to submission to the EIM."[75] In other words, NVE is not realizing intra-regional dispatch benefits in EIM because its system was already optimized. PacifiCorp is realizing intra-regional dispatch benefits in actual operations because its system was not already optimized. But these benefits are already reflected in the perfectly optimized GRID model.

Q. Does Staff make any additional arguments in support of reducing NPC for intra-regional benefits?

A. Yes. Staff speculates that because GRID is an hourly production model and the EIM is a five-minute balancing market, actual EIM operations are more efficient

[75] PAC/412 (CAISO 2016 Q1 Report, "Benefits for Participating in EIM." at 6).

than the GRID model, resulting in intra-regional benefits not captured in GRID.[76]

Q. Do you agree?

A. No. GRID is an hourly model that assumes there are no changes in loads and resources within the hour. The GRID model does not include the costs of within-hour re-dispatch, and therefore within-hour savings are inapplicable to GRID.

Q. Please elaborate.

A. Because GRID has unchanging load across each hour, it is comparable to dispatching thermal resources and market transactions across twelve identical five-minute blocks in an hour—because the load is identical, the results are identical.

Q. How does the Company balance its system under current operations?

A. Other than EIM, PacifiCorp does not have access to any other market facilitating transactions on a five-minute basis. As a result, during each hour the Company must dispatch its own resources to offset any changes in loads or variable generation across the hour. If load is increasing, the Company will need to back down its generation in the start of the hour and dispatch additional generation at the end of the hour. Because the lowest cost resources are dispatched first, lower cost resources will be backed down in the start of the hour, and higher cost resources will be dispatched up at the end of the hour. Load and variable generation vary continuously, and every hour will have both periods that are above the hourly average and periods that are below the hourly average. The result is higher costs relative to an hourly model with no changes across the hour.

Q. How does EIM impact within-hour dispatch?

[76] Staff/100, Crider/11.

A. The EIM re-dispatches the Company's resources, as well as CAISO resources, every five minutes to optimally serve the combined PacifiCorp and CAISO load, subject to the EIM transmission limits. PacifiCorp resources that are lower cost than CAISO resources would be dispatched to a greater extent, resulting in EIM transfers from PacifiCorp to the CAISO, and PacifiCorp resources that are higher cost than CAISO resources would not be dispatched as much, resulting in EIM transfers from the CAISO to PacifiCorp. The benefit of these inter-regional EIM transactions is captured in the 2017 TAM as an adjustment to the GRID-modeled NPC.

Q. What is the basis for CUB's adjustment to include intra-regional dispatch benefits?

A. CUB argues that the Company's adjustment to add costs related to day-ahead and real time system balancing transactions reflect the costs of balancing the system that a perfectly optimized GRID model does not recognize. Therefore, CUB reasons that the Company's adjustment for system balancing transactions effectively de-optimizes GRID so that customers no longer receive the benefits of GRID's perfectly optimized dispatch.[77] CUB further claims that because the data used to justify the system balancing transactions adjustment is all from pre-EIM operating periods, customers are not receiving the EIM benefits resulting from more efficient dispatch and therefore an additional adjustment is necessary to recognize the intra-regional dispatch benefits.[78]

[77] CUB/100, McGovern/13.
[78] CUB/100, McGovern/13.

Q. Do you agree that including the adjustment for system balancing transactions adjustment de-optimizes the GRID model dispatch?

A. No. As described in detail earlier in my testimony, the Company's adjustment captures costs related to the timing of system balancing transactions (*i.e.*, purchasing energy prior to the hour when the market price is higher than average, and selling energy prior to the hour when the market price is lower than average) and the inability to transact in the market for the exact quantities needed to balance the system each hour. Rather than de-optimizing GRID, the system balancing transaction adjustment is required to recognize the true cost of transacting in the market when energy is needed to balance the system. Even with the adjustment, the GRID model optimizes the Company's fleet of resources based on the economics of each plant and with perfect foresight of conditions in the model each hour.

Q. Will EIM dispatch reduce the cost of system balancing transactions?

A. No. The transactions that are subject of the system balancing transaction adjustment all occur prior to the hour and are necessary to balance the Company's system. To participate in the EIM, the Company must demonstrate that it has already balanced its system for the upcoming hour. Therefore, all of the system balancing transactions necessarily occur before EIM transactions and cannot be eliminated or reduced by the Company's participation in the EIM.

Q. What do you recommend with regard to the intra-hour EIM dispatch benefits?

A. The Commission should reject the adjustments proposed by Staff and CUB to impute intra-regional benefits into the TAM NPC because the GRID model already reflects an optimized dispatch of the Company's system. Introducing an additional adjustment would improperly double-count these benefits.

EIM Benefits – Bid Cost versus Production Cost

Q. How did the Company calculate the inter-regional dispatch benefits resulting from the EIM?

A. The inter-regional dispatch benefits are the benefits that the Company realizes from either exporting its lower cost energy to other EIM participants, or importing lower cost energy from other EIM participants to serve the Company's load:

- *Export* benefits reflect the difference between the Company's revenues from exports to the CAISO and the incremental cost of the Company's generation resources that supported the transfer.
- *Import* benefits reflect the difference between the incremental cost of the Company's generation resources that would otherwise have been dispatched, and the costs of imports from the CAISO.

Q. Is the Company's calculation of these benefits the same as in last year's TAM?

A. Yes, subject to the refinement discussed above. The Commission approved the Company's modeling in docket UE 296 and specifically rejected several adjustments related to inter-regional dispatch benefits.[79] In the Company's Reply Update, the calculation of inter-regional dispatch benefits related to the participation of NVE was updated to incorporate actual operational data not previously available, but the general approach to using the data in the benefits

[79] Order No. 15-394 at 8-9.

calculation is consistent with the calculation of inter-regional benefits between PacifiCorp and the CAISO.

Q. Please describe the issue raised by Staff regarding the calculation of inter-regional EIM benefits in the Company's Initial Filing.

A. Staff believes that the Company's method for calculating inter-regional dispatch benefits is incorrect. Staff's testimony explains that the Company derives the inter-regional benefits based on the difference between the price paid for the transfer of energy and the cost incurred or avoided by PacifiCorp. Staff provides a simplistic equation demonstrating the benefits derived from an export as:

Benefit = Revenue from transfer – cost to generate transfer energy

Staff agrees that this is the correct formula for calculating the benefits, but expresses concern that "the Company calculates the difference between the price paid by CAISO for the transfer and the *aggregated bid price* at the PACW trading hub, rather than calculating the difference between the price paid for energy by CAISO and the actual production cost incurred by the Company."[80] Staff recommends that the inter-regional dispatch benefits be calculated using the difference between the CAISO market price and the actual production cost incurred by the Company.[81] Staff did not quantify this adjustment.

Q. How does Staff justify its claim that the Company calculated the inter-regional benefits using aggregated bid prices, rather than actual production costs?

[80] Staff/100, Crider/13 (emphasis in original).
[81] Staff/100, Crider/15.

A. Staff compares average annual production costs of Company resources to what Staff understands to be the aggregate bid prices supplied by PacifiCorp to the CAISO and concludes that the aggregate bid price consistently exceeds the production costs, which results in lower inter-regional dispatch benefits.[82]

Q. What are the production costs calculated by Staff?

A. In Staff/103, Staff provides an estimate of the production cost of the Company's thermal generating units as projected in the 2017 TAM test period. This exhibit shows that the annual average cost of coal plants is approximately $19.93 per MWh and the average cost of natural gas plants (excluding the Gadsby units) is approximately $17.89 per MWh.

Q. What are the bid prices calculated by Staff?

A. In Staff/104, Staff provides the monthly average load aggregation point (LAP) market prices in the EIM during 2015 and describes that they range from a low of $17.60 per MWh to a high of $30.58 per MWh, which is generally higher than the average production cost. Because the LAP prices are generally higher than average production costs, Staff concludes that relying on the aggregate LAP as a proxy for the cost of generation will overstate the cost and understate the resulting inter-regional EIM benefits.

Q. Is it true that the Company uses the aggregate bid price, or LAP, as the cost of generating resources in the EIM benefits equation?

A. No. Staff misunderstands the purpose of the LAP, which is to determine the cut-off point for resources that were used to export energy to the CAISO. Contrary to Staff's claim, the LAP is not the cost of production used to determine EIM

[82] Staff/100, Crider/14.

benefits. In fact, the Company calculates the inter-regional dispatch benefits the same as Staff's recommendation.

Q. Please explain what the LAP price represents.

A. The LAP price is a market clearing price and represents the marginal cost to supply the next megawatt-hour of energy in a given geographic area. In other words, it represents the cost of the next generator that would be used to supply the next megawatt-hour of demand after all other less expensive resources are utilized. The marginal resource may be one of the Company's resources, or it may even be the cost of a resource in another BAA.

Q. How does the Company use the LAP price when determining the cost to supply transfers in EIM?

A. As I described in my direct testimony, to determine the cost of EIM transfers the Company builds a daily resource stack including all EIM-participating resources. The cost of each individual resource is equal to its EIM energy bid into the market, which represents the variable operating cost for that unit for a given period and generator configuration.[83] The resources are stacked from lowest to highest cost and the volume associated with each bid segment is identified. Starting with the lowest cost unit, EIM dispatches resources up until the total output matches demand for that interval. Because the LAP price represents the market clearing price after all demand, including transfers, has been met, it represents the cutoff within the Company's resource stack delineating which resources would have been utilized in that interval to serve load or supply a

[83] The PacifiCorp EIM energy bids are described further in the Company's 1st Supplemental Response to Staff Data Request 46.

transfer. For example, if the LAP price is $30 per MWh in an interval, Company resources costing less that than amount would have been used to serve load and supply exports.

When the Company is exporting, the first unit with a cost that is lower than the LAP price is identified from the supply stack. This represents the last unit the Company dispatched, and the cost is assigned to the EIM transfer. The calculation moves down the supply stack until the entire export volume is covered, identifying the cost and volumes of the specific resources during the intervals with EIM transfers. For the benefits calculation the total cost of the transfer is equal to the cost of each individual resource multiplied by the volume provided by that resource.

Q. Can you illustrate how this calculation works?

A. Yes. Confidential Figure 5 below provides a graphic illustration of one EIM interval on December 2, 2015. The line labeled "Supply Curve" represents the resource stack for December 2, including the quantities available for EIM at participating resources and the cost for each. In this five-minute interval, there was an export of [Begin Confidential] [redacted] [End Confidential]. Because the PACW LAP was [Begin Confidential] [redacted] [End Confidential] for this interval, the cost of the transfer was determined by identifying the highest cost resources in the stack at or below the PACW price. The [Begin Confidential] [redacted] [End Confidential] so the cost of all [Begin Confidential] [redacted] [End Confidential] is included in the cost of the transfer. The cost for the additional [Begin Confidential] [redacted] [End Confidential], the next resource in the stack with available capacity, [Begin Confidential] [redacted] [End Confidential]. The revenue received for the transfer is priced at the average of the Malin and PACW market prices, represented by the line [Begin Confidential] [redacted] [End Confidential]. The net benefit of the export in this interval, represented by the shaded rectangle, is equal to the revenue received less the cost of the resources identified in the stack.

[Begin Confidential]

Confidential Figure 5

[redacted]

[End Confidential]

Q. Using this resource stacking method, what was the resulting average cost of production to supply EIM exports during 2015?

A. Confidential Table 3 below shows a summary of the margin calculation for transfers from PACW to the CAISO during 2015. The average cost of energy of the units used to calculate the benefits of the PACW to CAISO transfer was $17.23 per MWh, which is closely in line with the production costs shown in Staff/103.

[Begin Confidential]

Confidential Table 3

[redacted]

[End Confidential]

Q. In Staff/105, Staff calculates an average cost of production for plants serving EIM transfers from January through September 2015. Please identify the problems with that calculation.

A. First, Staff/105 is based on data from two different time periods. The production costs used for each resource are the average annual production cost from the TAM forecast for calendar year 2017, while the EIM transfers are from January to September 2015. Second, the Lake Side 1 resource is included in the table but is labeled as a hydro unit with zero production costs, likely due to the fact that the underlying data labeled the Lake Side 1 volumes as "Dynamo," the name of the substation next to the plant. Third, the transfer volumes were taken from a workpaper showing the resources designated as being transferred for greenhouse gas compliance purposes.

Q. What is your recommendation regarding Staff's inter-regional dispatch benefit adjustment?

A. Staff's adjustment is based on its misunderstanding of how the Company quantifies the inter-regional dispatch benefits. The Company agrees with Staff that the inter-regional dispatch benefits should be the difference between the revenue earned and the actual costs of production, not the LAP. The Company's calculated benefits are consistent with Staff's recommendation and no additional adjustment is needed.

EIM Benefits – Opportunity Costs

Q. Please describe the issue raised by CUB regarding opportunity costs in the calculation of EIM benefits.

A. Based on its review of the workpapers supporting the calculation of the EIM benefits in the 2016 and the 2017 TAM, CUB concludes that the Company "seems to subtract the difference between the California-Oregon Border market hub (COB) and EIM prices as a lost opportunity cost."[84] CUB argues that it is inappropriate to include opportunity costs in the calculation of inter-regional EIM benefits; rather, the revenue received should be netted against the generation and variable costs of the resources utilized. CUB recommends that the Company remove the purported opportunity cost adjustment to EIM benefits.[85] CUB did not quantify the adjustment.

Q. How do you respond to CUB's proposal?

A. I agree with CUB that the opportunity cost of transacting at the COB market should not be subtracted from the inter-regional EIM benefits. In fact, the Company did not do so.

Q. What is the basis for CUB's claim that the Company's inter-regional dispatch benefits are reduced to account for the opportunity cost of transacting at COB?

A. CUB's claim appears to be based on a misunderstanding of a column label in the Company's workpapers. The confidential workpaper, which was attached to CUB's testimony as CUB/109, includes a column labeled "Export Benefit *excluding* Lost Opportunity & Fees."[86] This label was intended to convey that the COB market prices were *not* being subtracted from the benefits calculation.

Q. Does CUB's testimony identify where the Company allegedly subtracts the opportunity cost?

[84] CUB/100, McGovern/17.
[85] CUB/100, McGovern/19.
[86] CUB/109 (emphasis added). CUB/109 is a confidential workpaper from the 2016 TAM showing a calculation of the inter-regional EIM benefits for September 2015.

A. No. CUB claims that the opportunity cost is calculated as the difference between the EIM and COB prices and that this amount is subtracted from the EIM benefits. But when asked in discovery to identify where the COB prices were used to calculate the opportunity cost, CUB was unable to do so.[87] Instead, CUB simply stated that they "believe" this subtraction occurs and that the Company "seems to incorporate opportunity costs into the EIM cost approach."[88] This is insufficient to establish CUB's claims.

Q. Has the Company provided additional support for the inter-regional benefit calculation illustrating that the benefits are equal to the revenue received less the variable cost of generation?

A. Yes. In its Initial Filing the Company provided monthly revenue and costs from inter-regional EIM transfers. As I described in my direct testimony, the Company updated the benefits calculation in the 2017 TAM to include additional operational data and to more precisely identify specific generators that could have been incremented or decremented to facilitate exports and imports in the EIM. Because the data has become so voluminous, the calculation was transitioned to a database with summary reporting on a monthly basis. In an effort to show the details of the calculation, the Company provided a pricing example for a single interval demonstrating that the benefits are the net of revenue received less the variable costs incurred.[89] Confidential Table 3 above also shows a summary of the benefits calculation for exports from PacifiCorp to the CAISO, demonstrating that the inter-regional benefits are equal to revenue received less the cost of

[87] PAC/413 (CUB Response to PacifiCorp Data Request 7).
[88] *Id.*
[89] This information was provided in the Company's 1st Supplemental Response to Staff Data Request 46.

generation supporting transfers, and that the cost of generation from 2015 is in-line with the production costs included in the 2017 TAM.

Q. What do you recommend to the Commission?

A. While the Company agrees in concept with the issues raised by CUB, because the calculation of inter-regional EIM benefits in the 2017 TAM does not include a discount for opportunity costs, no adjustment is warranted.

EIM Benefits – Transmission Utilization Factor

Q. Please describe the issue raised by CUB regarding a potential discount in the calculation of EIM benefits due to transmission utilization.

A. CUB argues that the Company improperly discounts inter-regional EIM benefits by applying a transmission utilization factor that unreasonably limits the actual benefits realized by the Company based on purported transmission constraints between PacifiCorp and the CAISO.[90]

Q. Does the Company apply the transmission utilization factor to determine inter-regional EIM benefits prior to including the benefits in the TAM?

A. No. The Company calculates the actual benefits of exports based on the revenue received less the cost to supply the export, and the actual benefits of imports based on the price paid for the import less the cost of generation avoided.[91] CUB correctly describes this calculation, but incorrectly claims that the amount is then discounted by applying a transmission utilization factor.

Q. How are the inter-regional benefits applied to the forecast test period in the TAM?

[90] CUB/100, McGovern/15.
[91] CUB/100, McGovern/14.

A. As in the 2016 TAM, exports and imports between PacifiCorp and the CAISO are treated slightly different.

Q. How are exports treated?

A. For exports, the southbound transfer capability between PACW and the CAISO has a significant impact on the amount of benefits realized. The transmission available for EIM use is limited by two factors. First, the California-Oregon Intertie (COI) path rating is influenced by the status of a large number of interdependent components and is frequently de-rated due to forced and planned outages.

Second, the Company's forward transactions delivered at COB also use the Company's available transmission rights—if the Company has scheduled forward transactions that use COI capacity, there is less transfer capacity available for EIM transactions. Even if transmission is available for the EIM, actual historical data shows that not all of the capacity is used to support exports from the Company to the CAISO. In order to apply the historical export benefits to the 2017 forecast, the actual benefits (undiscounted) are divided by the total transmission that was available for EIM during the historical period and expressed in dollars per MWh of available transmission. This margin is then applied to the transmission in the 2017 TAM that is available for EIM. This approach ensures the transmission constraints are recognized and that transmission capacity is not utilized both for sales to the COB market and EIM.

Q. How are imports treated?

A. Imports between the CAISO and PACW are not typically subject to the same transmission constraints as exports because prices in the CAISO BAA are normally higher than in the Company's BAAs, limiting the amount of northbound energy flows. As a result, the Company simply includes an annual level of historical import benefits in the 2017 forecast, without any discount or transmission limitation.

Q. Is this the same approach approved by the Commission in the 2016 TAM for inter-regional EIM benefits between PacifiCorp and the CAISO?

A. Yes.

Avian Compliance Curtailment

Q. Please describe the adjustment proposed by Staff associated with avian compliance curtailments.

A. The Company reduced generation output at two wind sites[92] to reflect expected energy lost from implementing avian protection curtailments to comply with a court order issued by the United States District Court in Wyoming to enforce the Migratory Bird Treaty Act (MBTA). Staff argues that the avian curtailment is the result of PacifiCorp imprudence in siting its wind facilities "in an identified avian-sensitive location contrary to agency guidance"[93] Therefore, Staff recommends that all costs associated with avian curtailment costs be removed from NPC.[94]

Q. Has this issue been addressed in a previous TAM?

[56] The curtailments affect the Glenrock/Rolling Hills wind site, consisting of the Glenrock, Rolling Hills and Glenrock III wind projects, and the Seven Mile Hill wind site, consisting of the Seven Mile Hill and Seven Mile Hill II wind projects. Rolling Hills is not included in the 2017 TAM, so curtailment at that site does not affect the Company's filing.
[93] Staff/200, Kaufman/18.
[94] Staff/200, Kaufman/17-19.

A. Yes. Lost energy resulting from avian protection curtailments was first included in the 2016 TAM. In Order No. 15-394, the Commission rejected an adjustment similar to that proposed by Staff, concluding that the Company's modeling, including avian curtailment, "will yield a more accurate wind generation forecast[]" and that "PacifiCorp must comply with the court order for avian compliance."[95]

Q. What is the effect of Staff's adjustment to remove avian compliance curtailment?

A. Staff's adjustment overstates the amount of wind generation included in the TAM forecast. Total generation at the Company's owned wind plants is included in the test period using projections of a median, or "p50," output prepared at the time a project was first developed.[96] To account for avian compliance curtailment under the modeling approved by the Commission in the 2016 TAM, the p50 forecast is reduced for each applicable site to reflect lower wind generation. By eliminating this adjustment, Staff's proposal artificially increases wind generation beyond the level that is reasonably expected during 2017 and ignores the "most recent reliable data."[97]

Q. How do you respond to Staff's claim that the Company imprudently sited its wind projects in a manner that was contrary to agency guidance?

A. While I am not a lawyer, I understand that Staff's characterization over-simplifies and applies hindsight review to the issue. It is my understanding that the

[95] Order No. 15-394 at 7.
[96] The P50 forecast for Glenrock is increased by 1 percent in compliance with the Commission's order in docket UE 200. *In the Matter of PacifiCorp's 2009 Renewable Adjustment Clause*, Docket No. UE 200, Order No. 08-548 (Nov. 11, 2008).
[97] Order No. 08-548 at 21.

enforcement of the MBTA is within the discretion of the United States Fish and Wildlife Service (USFWS) and that at the time that the Company constructed the wind projects, USFWS had never enforced the MBTA against a wind project.[98] I have been counseled that various courts of appeal and district courts have taken different positions on whether the taking of a migratory bird by lawful commercial business operations is a violation of the MBTA. In addition, the USFWS issued its final guidelines related to the MBTA and wind projects in 2012, years after the wind projects were sited and constructed. The "agency guidance" Staff refers to was *interim* guidelines adopted in 2003.

Q. Has Staff presented any evidence that the wind projects were imprudently sited?

A. No. Implicit in Staff's adjustment is a contention that it would have been imprudent for the Company to construct the wind projects if it had accounted for the curtailment necessary to comply with the MBTA. But nowhere does Staff make this argument or present any evidence that the Company was imprudent for siting the wind projects in an avian-sensitive location. Even with the curtailment, these projects enjoy relatively high capacity factors and are an important part of the Company's efforts to meet renewable portfolio standard compliance requirements. Had the Company instituted these curtailment measures from the beginning, the projects would be prudent and Staff has presented no evidence to the contrary.

Q. What do you recommend to the Commission?

[98] *See http://articles.latimes.com/2013/nov/24/nation/la-na-nn-wind-energy-eagle-death-20131123.*

A. The Commission should adhere to its decision in the 2016 TAM recognizing the actual costs of avian compliance curtailment. The curtailments are carried out in compliance with a court order and reflect the expected operation of the plants during 2017.

Forced Outages

Q. How did the Company model forced outages in this case?

A. The Company used an adjusted 48-month rolling average as the basis for its forced outage costs, consistent with Order No. 10-414 in docket UM 1355. The Company also modeled forced outages and unit de-rates as discrete events, rather than using a percentage de-rate to nameplate capacity in all hours. The Commission approved this approach in Order No. 15-394 in the 2016 TAM, because it more accurately forecasts the impact of forced outages on NPC.[99] In Figure 3 in my direct testimony I confirmed that under the modeling approach approved in the 2016 TAM the forecast distribution of coal plant availability closely matches the historical distribution.

Q. Has Staff proposed a change to the modeling of forced outage rates?

A. Yes. Staff recommends that the Commission reconsider the modeling change approved in the 2016 TAM because the methodology creates a pattern of short outages that, according to Staff, results in inflated NPC associated with restarting generation.[100] Staff proposes a new methodology for modeling forced outages derived from four distinct NPC values, one for each of the four years of the historical period used to forecast forced outages, using the average of those four

[99] Order No. 15-394 at 6.
[100] Staff/200, Kaufman/15.

NPC values to determine the impact of forced outages.[101] Staff did not fully quantify this adjustment, but using a single year of data, Staff estimated that its adjustment would decrease NPC by $1.3 million total-system, or $321,000 on an Oregon-allocated basis.[102]

Q. Is there any basis for Staff's claim that the Company's forced outage modeling inflates NPC due to modeling frequent restarts?

A. No. The fuel and operations and maintenance costs incurred when restarting a coal plant are not part of NPC and are not reflected in the Company's GRID results in this case. The Company's approach to modeling forced outages does not increase NPC related to restarting generation. Staff's modeling proposal seeks to remedy a problem that does not exist.

Q. Staff quantified the impact of its adjustment based a single year model run that was provided in discovery prior to Staff's reply testimony. Is the result the same if all four years are used, as suggested by Staff?

A. No. Staff's proposal requires the average of the GRID runs for four years of outages, but Staff based its conclusion that NPC would decrease under its proposal using only one year of data.[103] When all four GRID runs were completed[104] it showed that of the four historical years that Staff's proposal would cover, only one year had a lower cost than the Company's proposal, while three had higher costs. Thus, adoption of Staff's adjustment would actually increase

[101] Staff/200, Kaufman/15.
[102] Staff/200, Kaufman/16.
[103] Staff/200, Kaufman/16.
[104] The remaining GRID runs were provided in the Company's 1st Supplemental Response to Staff Data Request 71.

NPC in this case—further undermining Staff's claim that the Company's approach inflates NPC.

Q. Do you have any other concerns regarding Staff's proposed modeling?

A. Yes. Staff's proposal presents new modeling challenges associated with optimizing gas plant commitment and coal costs and volumes for four different scenarios. While the Company is willing to work with Staff to explore more refined methodologies for sequencing forced outages, the Company is reluctant to adopt any approach that adds complexity without also increasing forecast accuracy.

Q. Has Staff presented a reasonable basis for the Commission to modify the forced outage methodology approved in the 2016 TAM?

A. No. In the 2016 TAM, ICNU and Staff both opposed the Company's forced outage modeling, with ICNU arguing that the Company's modeling "will result in a pattern of frequent, short outages not representative of normalized operations."[105] This argument—which the Commission rejected—is effectively the same argument Staff makes here. Like ICNU last year, Staff's adjustment this year is deficient because Staff has not shown that its proposed change will result in a more accurate NPC forecast.

Modeling QF Contracts

Q. How did the Company model QF contracts in the TAM?

A. The Company's modeling in this case is consistent with its historical treatment of QF contracts in the TAM under stipulated amendments to the TAM Guidelines. If the QF is expected to reach commercial operation during the test period, then

[105] *See* Order No. 15-394.

the Company includes the costs of the QF contract in the NPC calculation, pro-rated to reflect the percentage of the test period during which the QF is expected to generate power.

Q. Please describe CUB's proposed adjustment to the treatment of QF contract costs.

A. CUB argues that the Company consistently over-forecasts QF generation in the TAM because the "Company forecasts the entire fleet of QFs available and serving customers from January 1, which means that customers will pay the higher rates [caused by QF purchases] starting January 1, for resources that were not used and useful."[106] CUB's adjustment removes from rates any QF that is not commercially operating on the date of the final TAM update, regardless of whether the QF is reasonably expected to operate during the test period.[107]

Q. Is CUB's proposal to disallow QF contract cost recovery reasonable?

A. No. CUB's proposal disregards the specific provisions in the TAM Guidelines governing this issue, and is based on a fundamental misunderstanding of how the Company models QF contracts in the TAM. Absent another mechanism to later account for the costs proposed to be excluded from the TAM (e.g. 100 percent true-up of QF costs through a PCAM or other mechanism), CUB's recommendation undermines PURPA's cost-recovery mandate.

Q. Do the TAM Guidelines address the inclusion of new contracts, QF or otherwise, in the TAM Final Update?

[106] CUB/100, McGovern/22.
[107] CUB/100, McGovern/24.

A. Yes. In the Company's 2011 TAM, docket UE 216, the Commission approved an all-party stipulation that amended the TAM Guidelines relating to the inclusion of contracts in the TAM.[108] Specifically, the parties agreed that the Company will attest "that all contracts executed prior to the contract lockdown date have been included in the Indicative Filing and will identify any exceptions and the reason why such contracts were excluded."[109] This provision requires the Company to include all executed QF contracts for the test period.

Q. Do the TAM Guidelines also specifically address the inclusion of new QF contracts in the TAM?

A. Yes. In the 2015 TAM, docket UE 287, the Commission approved a new provision to the TAM Guidelines to address the inclusion of new QF contracts in the TAM forecast. In that case, ICNU questioned whether the TAM should include new QFs that were forecast to become operational just before or during the test period. The Company, ICNU, Staff—and CUB—resolved the issue through the Company's agreement to include a new provision in the Indicative Filing attestation confirming that the Company has a "commercially reasonable good faith belief that the new QFs will reach commercial operation during the rate effective period."[110] The joint testimony filed by the settling parties in support of the stipulation clarifies, "PacifiCorp's attestation will be based on the information

[108] *In the Matter of PacifiCorp's 2011 Transition Adjustment Mechanism*, Docket No. UE 216, Order No. 10-363 (Sept. 16, 2010).
[109] *Id.*, App. A at 5.
[110] *In the Matter of PacifiCorp's 2015 Transition Adjustment Mechanism*, Docket No. UE 287, Order No. 14-331 at 5 (Oct. 1, 2014).

known to it as of the contract lockdown date, but does not require PacifiCorp to opine regarding the commercial viability of any QF."[111]

Q. Does CUB address these provisions of the TAM Guidelines in proposing its adjustment?

A. No. CUB does not acknowledge these provisions or explain why they are inadequate to address its concerns.

Q. How does CUB characterize the Company's modeling of QF contracts in the TAM?

A. CUB states that the Company's NPC calculation assumes that every QF is operational for the entire TAM test period, regardless of when the QF is expected to become operational. Based on this understanding, CUB testifies that after the 2015 TAM, only 80 MW of the 96 MW of QF generation that was forecasted actually became operational.[112] CUB further claims that the apparent forecasting error became "drastically worse" in the 2016 TAM.[113] CUB claims that the Company had forecasted a total of 1,006 MW of solar QFs during 2016, but only the 80 MW already online was operational and not a single one of the forecast projects had come online.

Q. Is CUB's characterization of the Company's modeling correct?

A. No. Contrary to CUB's testimony, the Company's TAM forecast includes QF contracts in the NPC calculation only as of the date they are expected to reach commercial operation. For example, if a QF is expected to achieve commercial

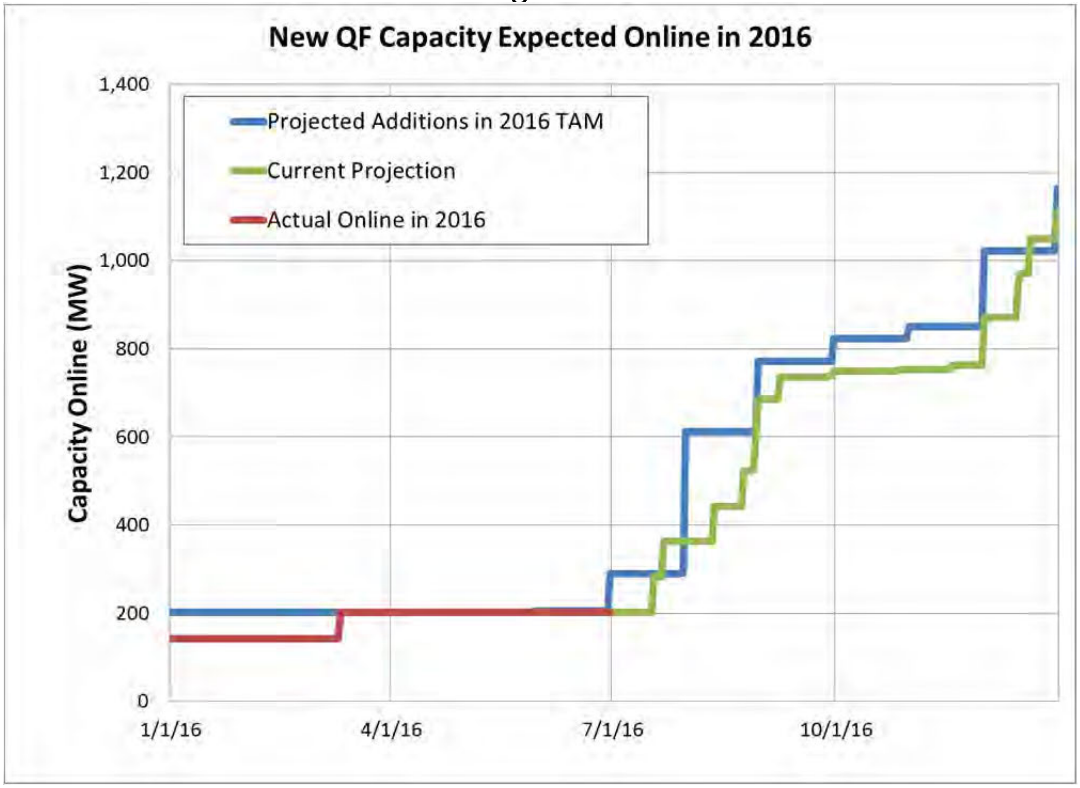
[111] Docket No. UE 287, Settling Parties/100, Dickman, Ordonez, Garcia, Jenks & Mullins/11 (Aug. 14, 2014).
[112] CUB/100, McGovern/21-22.
[113] CUB/100, McGovern/21-22.

operation on December 1 of the test period, only one month of the QF contract costs are included in the TAM.

Q. How do you respond to CUB's claim that the Company's forecasting of QF operations became "drastically worse" in the 2016 TAM?

A. CUB's claim is in error. Figure 6 below shows the new QF capacity that was projected to come online in the 2016 TAM, the actual capacity that had reached commercial operation by June 30, 2016, and an update forecast of QF additions through the end of 2016 based on the most up-to-date information available. Out of a total 1,164 MW of new QFs (including all generation types) included in the final 2016 TAM, the Company currently expects 1,112 MW, or 96 percent of the total forecast, to be online by the end of 2016. The attestation discussed earlier will support the Company's Final Update which will reflect the most current information on these QF projects.

Figure 6



Q. CUB also argues that QF developers have an incentive to delay commercial operation as long as possible "all the while stating that is expects the facility to come online sooner."[114] Is this a reasonable basis to deny cost recovery?

A. No. To the extent that CUB believes that developer incentives are in opposition to customer interests, the remedy is to better align developer and customer interests, *e.g.*, by modifying the liquidated damage provisions in QF contracts. Denying cost recovery to PacifiCorp does nothing to eliminate the developer incentive CUB perceives.

Q. How does CUB's recommendation undermine PURPA?

A. PURPA requires the Company to purchase energy and capacity from QFs at avoided cost prices under terms and conditions established by each state public

[114] CUB/100, McGovern/22-23.

utility commission. As such, the risks associated with QF performance are largely outside the Company's control. In addition, PURPA specifically mandates cost recovery.[115] CUB's recommendation, which disallows timely recovery of certain QF contract costs, undermines PURPA's policy of utility cost recovery.

Q. What do you recommend with regard to inclusion of QF contracts in the 2017 TAM?

A. The Commission should continue to rely on the stipulated provisions of the TAM Guidelines approved to address this issue. These provisions address the concerns raised by CUB in a fair and reasonable manner.

Direct Access – REC Obligation

Q. As in docket UE 296, Noble Solutions again recommends that the Schedule 294, 295 and 296 transition adjustments be adjusted to reflect the value of freed-up RECs resulting from the departure of the direct access load.[116] How do you respond to this recommendation?

A. The Commission should once again reject this recommendation. In Order No. 15-394, the Commission rejected this adjustment because it incorrectly assumes that PacifiCorp will sell its RECs, direct access customers receive the benefits whenever RECs are sold, and the net present value of any freed-up RECs is *de minimus*.[117] Each of these reasons for rejecting the adjustment remain valid today.

Q. Does the Company continue to bank its RECs, as you testified in docket UE 296?

[115] 16 U.S.C. § 824a-3(m)(7).
[116] Noble Solutions/100, Higgins/18-22.
[117] Order No. 15-394 at 12.

A. Yes. The Company currently does not sell its Oregon-allocated RECs. Because Oregon allows for REC banking, the Company banks the unused RECs and uses them for future compliance.

Q. Will direct access customers continue to receive the benefits of RECs if they are sold?

A. Yes. To the extent the Company generates revenues from selling RECs, those revenues are passed back to all customers through the property transaction balancing account. Thus, departing direct access customers will receive a share of the benefits of those sales, if they should occur.

Q. Noble Solutions claims that circumstances have changed since docket UE 296 because Senate Bill (SB) 1547 increased the Company's RPS obligation.[118] How do you respond?

A. The Company's increased RPS compliance obligation resulting from SB 1547 does not justify Noble Solutions' proposal. Even with the higher RPS obligation, any freed-up RECs will have a *de minimus* value that is far outweighed by the administrative burden that would be required to implement Noble Solutions' proposal.

Q. Please describe the administrative burden necessary to implement Noble Solutions' proposal.

A. As I described in docket UE 296, to provide a credit to direct access customers, remaining customers would have to be surcharged. In addition, the RECs that are hypothetically sold will need to be separately tracked to ensure that if a direct access customer returns to cost-of-service rates, the customer does not receive any

[118] Noble Solutions/100, Higgins/19.

benefit from those RECs. Thus, the Company will be required to create multiple REC banks reflecting RECs that are "sold" by each departing direct access customer to remaining customers. The burden of this tracking process far outweighs any purported benefits to direct access customers.

Q. Noble Solutions also claims that SB 1547 has imposed higher RPS compliance costs on ESSs, thereby, justifying its proposal here.[119] How do you respond to this argument?

A. The fact that SB 1547 impacts ESSs has no impact on how the Company plans to comply with its RPS obligations.

Q. Are there any other problems with Noble Solutions' proposal?

A. Yes. There is no reliable way to determine the monetary value of freed-up RECs. Noble Solutions recommends using the average price of unstructured REC sales for 2015 to set the value of freed-up RECs for 2017.[120] As I testified in docket UE 296, this approach is fundamentally flawed. First, there is no basis to assume that the Company could sell a REC in 2017 for the same price as 2015. The REC market is volatile and illiquid and there is no basis to assume that market conditions in 2015 will be reflective of market conditions in 2017. Second, the Company is not able to sell all of the RECs that it markets and therefore it is pure speculation to assume that Company could actually realize value by selling the freed-up RECs. Therefore, any credit paid must be discounted to reflect the price received per marketed REC, not sold REC—a calculation that Noble Solutions

[119] Noble Solutions/100, Higgins/19.
[120] Noble Solutions/100, Higgins/22.

has not attempted in its proposal. Because there is no way to reliably value RECs, any value transferred to the ESS will be speculative.

Direct Access – Schedule 200 Escalation

Q. Noble Solutions also again recommends that the Consumer Opt-Out Charge included in the Company's Five-Year Transition Adjustment should decrease, rather than increase, in years 6 through 10.[121] How do you respond?

A. The Commission should once again reject this recommendation, as it did in dockets UE 267 and UE 296. When Noble Solutions made the same recommendation in docket UE 296, the Commission found that it is reasonable to hold fixed generation costs constant in real terms for years six through 10, as PacifiCorp had proposed.[122] Noble Solutions has presented the same evidence in this case and provided no basis for the Commission to reverse the conclusion reached in docket UE 267 and affirmed in docket UE 296.

Q. Is the Company's proposed Consumer Opt-Out Charge here consistent with the Commission's order in dockets UE 267 and UE 296?

A. Yes. The Consumer Opt-Out Charge escalates the Company's fixed generation costs at the average rate of inflation—meaning that, in real terms, the fixed generation costs are held constant through year 10.

Q. What is the basis for Noble Solutions' claim that the Consumer Opt-Out Charge should decline in years six through 10?

[121] Noble Solutions/100, Higgins/26-27.
[122] Order No. 15-394 at 12.

A. Noble Solutions claims that the impacts of accumulated depreciation on the Company's generation assets will cause the revenue requirement associated with those assets to decrease. Therefore, the Consumer Opt-Out Charge should also decrease.[123]

Q. Why is it necessary to include the escalation rate in the calculation of the Consumer Opt-Out Charge for years six through 10?

A. This treatment is necessary to account for the time value of money, allowing the fixed generation costs to be reduced to a present value for purposes of calculating the Consumer Opt-Out Charge. In fact, the exact same inflation adjustment is made to the fixed costs in years one through five as in years six through 10 because costs from both periods must be reduced to a present value to calculate the charge. The only difference between the two periods is that years six through 10 do not include costs of new investments. If it is appropriate to include an inflation adjustment in years one through five, as Noble Solutions concedes, then it is equally appropriate to have the same adjustment in years six through 10.

Q. Has Staff previously supported the approach approved by the Commission in dockets UE 267 and UE 296 to escalate the fixed generation costs in years six through 10?

A. Yes. In its opening testimony in docket UE 267, Staff specifically endorsed the escalation of fixed costs just as PacifiCorp proposed.[124] PGE's five-year

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[123] Noble Solutions/100, Higgins/26-27.

[124] Docket No. UE 267, Staff/100, Compton/6 ("**Q. Do you support PacifiCorp's projected escalation of its fixed generation costs in the construction of the Schedule 200 base supply portion of the direct access?** A. Yes. The desired escalation can be achieved by using two approaches. The first is to forecast escalation in fixed generation costs as PacifiCorp has done (aside from the staff recommendation of limiting those charges to a five-year period forecast). The second is to update the applicable fixed

program, which preceded PacifiCorp's, also includes the same methodology as here, which Staff described as resulting in "inclining fixed-cost transition fees."[125]

Q. Is there any basis to assume that the impact of accumulated depreciation will result in a declining Consumer Opt-Out Charge for years six through 10?

A. No. As the Company has previously testified, holding the fixed generation costs constant in real terms during years six through 10 is actually a conservative assumption. Noble Solutions' recommendation ignores numerous other aspects of fixed generation costs that will increase during those years. Fixed generation costs include many different types of costs to operate and maintain existing generation assets, including items such as the cost of overhauls, which will be higher in future years compared to past overhauls, routine capital expenditures required to maintain plants, costs related to union labor contracts, chemical costs, and vehicle fuel costs. Noble Solutions' assertion that accumulated depreciation is the only aspect that is changing in years six through 10 is simply wrong.

Q. Does this conclude your reply testimony?

A. Yes.

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generation rates as PacifiCorp has those rates changed through general rate cases. The latter approach was supported in the Docket UE 262 settlement. Staff is fine with either approach.").

[125] *See* Docket No. UE 262, Staff/300, Compton/10-11.

Docket No. UE 307
Exhibit PAC/401
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

TAM Allocation Reply Filing 2017

August 2016

PacifiCorp
CY 2017 TAM

Line no		ACCT.	Total Company: UE-296 Final TAM CY 2016	Total Company: TAM CY 2017 - Initial Filing	Total Company: TAM CY 2017 - Reply Update	Factor	Factors CY 2016	Factors CY 2017	Oregon Allocated: UE-296 Final TAM CY 2016	Oregon Allocated: TAM CY 2017 - Initial Filing	Oregon Allocated: TAM CY 2017 - Reply Update
1	**Sales for Resale**										
2	Existing Firm PPL	447	14,551,883	12,491,680	14,235,193	SG	25.464%	25.230%	3,705,447	3,151,693	3,591,587
3	Existing Firm UPL	447	-	-	-	SG	25.464%	25.230%	-	-	-
4	Post-Merger Firm	447	308,215,401	264,081,138	354,617,969	SG	25.464%	25.230%	78,483,023	66,628,559	89,471,306
5	Non-Firm	447	-	-	-	SE	24.074%	23.757%	-	-	-
6	**Total Sales for Resale**		322,767,283	276,572,818	368,853,162				82,188,470	69,780,252	93,062,893
7											
8	**Purchased Power**										
9	Existing Firm Demand PPL	555	5,460,531	5,396,826	4,979,885	SG	25.464%	25.230%	1,390,453	1,361,637	1,256,442
10	Existing Firm Demand UPL	555	25,957,591	23,373,572	23,760,178	SG	25.464%	25.230%	6,609,761	5,897,231	5,994,773
11	Existing Firm Energy	555	33,163,822	31,518,350	30,712,777	SE	24.074%	23.757%	7,983,987	7,487,882	7,296,500
12	Post-merger Firm	555	539,019,217	550,503,265	601,586,184	SG	25.464%	25.230%	137,254,198	138,893,825	151,782,217
13	Secondary Purchases	555	-	-	-	SE	24.074%	23.757%	-	-	-
14	Other Generation Expense	555	6,783,968	7,635,782	7,546,940	SG	25.464%	25.230%	1,727,449	1,926,534	1,904,118
15	**Total Purchased Power**		610,385,128	618,427,794	668,585,963				154,965,848	155,567,108	168,234,050
16											
17	**Wheeling Expense**										
18	Existing Firm PPL	565	21,008,517	20,923,037	20,923,037	SG	25.464%	25.230%	5,349,544	5,278,953	5,278,953
19	Existing Firm UPL	565	-	-	-	SG	25.464%	25.230%	-	-	-
20	Post-merger Firm	565	119,121,361	117,404,391	116,941,986	SG	25.464%	25.230%	30,332,698	29,621,523	29,504,856
21	Non-Firm	565	8,447,062	7,680,770	7,707,729	SE	24.074%	23.757%	2,033,579	1,824,737	1,831,142
22	**Total Wheeling Expense**		148,576,940	146,008,198	145,572,752				37,715,820	36,725,212	36,614,951
23											
24	**Fuel Expense**										
25	Fuel Consumed - Coal	501	684,036,958	717,322,134	764,589,286	SE	24.074%	23.757%	164,677,719	170,415,756	181,645,114
26	Fuel Consumed - Coal (Cholla)	501	39,725,288	54,710,604	54,030,506	SE	24.074%	23.757%	9,563,620	12,997,715	12,836,143
27	Fuel Consumed - Gas	501	3,867,174	2,221,172	2,489,125	SE	24.074%	23.757%	930,998	527,689	591,347
28	Natural Gas Consumed	547	349,178,912	296,984,718	279,921,635	SE	24.074%	23.757%	84,062,690	70,555,295	66,501,582
29	Simple Cycle Comb. Turbines	547	3,229,791	2,464,889	2,637,534	SE	24.074%	23.757%	777,552	585,589	626,605
30	Steam from Other Sources	503	4,836,760	4,465,238	4,416,891	SE	24.074%	23.757%	1,164,420	1,060,816	1,049,330
31	**Total Fuel Expense**		1,084,874,883	1,078,168,755	1,108,084,977				261,177,000	256,142,860	263,250,121
32											
33	**Net Power Cost (Per GRID)**		1,521,069,669	1,566,031,929	1,553,390,530				371,670,199	378,654,929	375,036,229
34											
36	Oregon Situs Solar Projects		515,121	536,598	471,321	OR	100.000%	100.000%	515,121	536,598	471,321
37	**Total NPC Net of Adjustments**		1,521,584,790	1,566,568,527	1,553,861,851				372,185,320	379,191,527	375,507,550
38											
39	Non-NPC EIM Costs*		4,621,885	5,166,061	4,886,586	SG	25.464%	25.230%	1,176,903	1,303,414	1,232,902
35	Production Tax Credit (PTC)				(87,596,947)	SG		25.230%			(22,101,004)
40	**Total TAM Net of Adjustments**		1,526,206,675	1,571,734,588	1,471,151,490				373,362,223	380,494,941	354,639,448
41											
42	Increase Absent Load Change									7,132,718	(18,722,775)
43											
44	Oregon-allocated NPC Baseline in Rates from UE-296								$373,362,223		
45	$ Change due to load variance from UE-296 forecast								(6,633,884)		
46	2017 Recovery of NPC in Rates								$366,728,339		
47	*EIM Benefits for the 2017 TAM are reflected in net power costs										
48	**Increase Including Load Change**									**13,766,602**	**(12,088,892)**
49											
50	Add Other Revenue Change									1,168,275	1,167,096
51	Add PTC Revenue Requirement									4,975,106	
52	Add Change in Fixed Generation for PTC										27,085,374
53											
54	**Total TAM Increase**									**19,909,983**	**16,163,578**

Docket No. UE 307
Exhibit PAC/402
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

Results of Updated NPC Study Reply Filing 2017

August 2016

PacifiCorp

_Cum ORTAM17 NPC Study_2016 07 30 CONF

Net Power Cost Analysis

12 months ended December 2017	01/17-12/17	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	14,235,193	1,244,657	1,148,675	1,256,078	1,113,852	1,074,554	1,050,494	1,225,519	1,240,779	1,211,877	1,230,177	1,215,942	1,222,590
BPA Wind	2,687,120	342,225	256,241	277,493	207,909	227,367	146,535	124,412	109,081	158,228	208,299	285,920	343,411
Hurricane Sale	7,020	878	877	878	878	878	878	878	878	-	-	-	-
Leaning Juniper Revenue	87,522	5,564	5,819	9,110	5,407	5,986	6,219	9,972	10,534	8,795	7,600	6,140	6,376
UMPA II s45631	3,857,098	593,283	561,909	593,283	582,825	593,283	932,517	-	-	-	-	-	-
Total Long Term Firm Sales	20,873,953	2,186,606	1,973,521	2,136,841	1,910,870	1,902,067	2,136,642	1,360,780	1,361,271	1,378,900	1,446,077	1,508,002	1,572,376
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	53,568,380	17,383,410	15,962,760	17,752,050	802,000	834,080	834,080	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	53,568,380	17,383,410	15,962,760	17,752,050	802,000	834,080	834,080	-	-	-	-	-	-
System Balancing Sales													
COB	29,759,341	4,189,931	3,207,060	3,908,791	1,096,840	331,377	876,880	1,265,776	2,848,050	3,938,641	2,890,510	2,597,048	2,608,437
Four Corners	75,377,101	6,164,818	4,482,675	5,918,924	4,831,595	4,677,639	4,433,457	5,850,317	9,777,208	8,734,646	7,667,581	6,218,883	6,619,357
Mead	33,156,459	3,611,523	1,801,078	2,518,402	2,141,537	2,110,302	2,105,409	2,680,569	3,250,857	3,418,874	3,098,904	2,996,687	3,422,317
Mid Columbia	30,521,020	3,155,966	700,264	5,796,297	2,372,981	2,129,916	1,173,885	2,654,600	3,582,586	3,333,806	2,477,805	1,656,639	1,486,275
Mona	25,565,505	2,393,374	1,414,811	1,043,398	2,059,410	3,065,323	1,746,406	1,511,237	2,057,599	3,688,785	1,765,374	2,740,393	2,079,394
NOB	1,323,206	11,498	105,879	-	50,533	99,582	377,968	420,550	138,975	-	-	37,138	81,082
Palo Verde	84,705,326	869,761	457,945	257,877	7,626,164	7,085,886	8,437,214	10,684,859	8,813,045	9,212,276	10,654,442	10,516,030	10,089,828
EIM Exports	13,947,864	837,072	779,773	734,470	935,519	1,071,542	1,877,274	1,933,612	1,689,901	1,366,784	872,056	878,413	971,447
Trapped Energy	55,007	8,803	94	-	-	1,775	-	-	-	-	4,767	593	38,976
Total System Balancing Sales	294,410,829	21,242,746	12,949,580	20,178,159	21,114,578	20,573,342	21,028,493	27,001,521	32,158,221	33,693,813	29,431,439	27,641,825	27,397,112
Total Special Sales For Resale	368,853,162	40,812,761	30,885,861	40,067,051	23,827,448	23,309,489	23,999,215	28,362,300	33,519,492	35,072,714	30,877,515	29,149,828	28,969,488

PacifiCorp

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Net Power Cost Analysis

12 months ended December 2017	01/17-12/17	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental	958,250	24,840	186,719	-	33,120	24,840	293,685	229,080	-	4,140	8,280	8,280	145,268
Combine Hills Wind	4,755,800	336,025	407,156	494,419	492,219	421,026	360,909	392,436	346,530	293,313	355,247	438,875	417,645
Deseret Purchase	36,627,600	3,125,456	2,997,764	3,125,456	3,082,892	2,572,134	3,082,892	3,125,456	3,125,456	3,082,892	3,125,456	3,056,290	3,125,456
Douglas PUD Settlement	2,260,264	92,498	45,126	143,707	273,958	284,600	318,055	342,777	276,433	116,064	126,170	112,145	128,730
Eagle Mountain - UAMPS/UMPA	2,829,034	206,120	172,597	167,442	256,297	334,339	450,285	340,166	322,110	180,005	119,359	111,987	168,325
Gemstate	1,327,500	105,600	102,300	104,500	102,300	102,300	102,300	102,300	114,900	102,300	125,000	158,100	105,600
Hermiston Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Purchase	83,044	10,380	10,381	10,380	10,380	10,380	10,380	10,380	10,380	-	-	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	6,804,970	569,420	553,380	573,430	573,430	573,430	565,410	561,400	561,400	557,390	573,430	573,430	569,420
Nucor	7,129,800	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
Old Mill Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
P4 Production	19,999,999	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
Pavant III Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE Cove	154,785	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899
Rock River Wind	4,834,277	629,232	488,673	514,014	423,855	276,752	254,668	166,493	196,761	267,332	519,266	553,293	543,938
Small Purchases east	14,288	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	20,962,425	2,805,703	1,816,660	2,149,531	1,624,023	1,436,385	1,208,070	854,752	1,020,918	1,113,901	1,817,062	2,437,015	2,678,408
Top of the World Wind	41,902,933	5,548,005	3,686,827	4,334,908	3,333,919	2,970,104	2,449,666	1,956,114	2,012,140	2,226,881	3,695,185	4,771,487	4,917,700
Tri-State Purchase	10,388,149	935,134	782,633	763,953	702,635	740,235	842,364	1,085,178	1,024,851	950,126	892,338	799,053	869,651
Wolverine Creek Wind	9,929,128	723,195	845,002	1,076,905	990,530	749,254	802,224	739,900	621,233	654,338	890,756	1,030,723	805,068
Long Term Firm Purchases Total	170,962,246	17,386,496	14,370,146	15,733,530	14,174,445	12,770,728	13,015,825	12,181,373	11,908,030	11,823,550	14,522,422	16,325,602	16,750,099
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

PacifiCorp

_Cum ORTAM17 NPC Study_2016 07 30 CONF

Net Power Cost Analysis

12 months ended December 2017	01/17-12/17	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Qualifying Facilities													
QF California	7,101,728	655,496	733,271	822,755	1,039,444	1,055,106	815,226	388,011	293,607	271,727	273,460	303,435	450,189
QF Idaho	7,705,331	627,479	582,096	647,255	675,219	789,478	852,007	785,526	674,001	633,023	493,560	484,808	460,880
QF Oregon	47,337,477	2,956,221	3,002,392	3,588,529	4,568,856	5,115,587	5,078,952	4,868,105	4,598,835	4,116,177	3,538,081	2,825,327	3,080,415
QF Utah	9,955,208	686,869	711,288	842,201	883,570	966,957	984,556	917,334	908,079	852,668	817,029	725,116	659,541
QF Washington	289,953	-	-	-	11,400	26,395	46,567	62,073	66,363	54,308	22,846	-	-
QF Wyoming	200,930	20,883	20,160	23,124	15,756	14,190	11,322	13,844	14,321	12,840	13,067	20,342	21,081
Biomass One QF	14,869,664	1,399,748	1,300,383	1,395,037	1,129,345	888,319	866,565	880,091	1,518,511	1,593,094	1,323,760	1,268,565	1,306,248
DCFP QF	179,660	10,904	10,011	13,832	14,156	20,774	22,771	18,415	14,878	12,491	21,505	13,540	6,382
Enterprise Solar I QF	11,776,513	575,402	624,569	896,870	1,025,481	1,281,175	1,358,744	1,548,412	1,388,445	1,164,791	836,595	591,160	484,870
Escalante Solar I QF	11,131,922	525,988	582,855	852,108	986,414	1,183,991	1,273,621	1,448,734	1,338,703	1,095,782	816,063	561,318	466,346
Escalante Solar II QF	10,639,749	503,123	557,403	814,322	942,804	1,131,363	1,217,462	1,384,137	1,278,973	1,047,120	779,924	536,946	446,174
Escalante Solar III QF	10,198,285	488,922	543,066	788,212	914,280	1,097,593	1,178,609	1,333,907	1,235,361	1,011,006	707,954	490,968	408,408
Evergreen BioPower QF	3,038,493	241,956	205,414	230,542	208,662	208,149	237,682	320,484	295,792	295,002	311,253	227,742	255,815
Five Pine Wind QF	7,621,534	522,326	714,520	677,297	661,672	475,334	472,945	586,275	604,204	620,651	690,306	806,955	789,050
Foote Creek III Wind QF	1,616,034	181,968	164,042	219,609	135,665	81,441	75,844	74,500	94,887	103,417	162,332	179,721	142,607
Granite Mountain East Solar QF	11,339,695	567,379	636,527	927,418	1,024,731	1,208,968	1,317,924	1,396,127	1,325,686	1,015,719	838,279	599,442	481,495
Granite Mountain West Solar QF	7,510,615	375,710	421,478	615,336	680,035	801,178	872,514	925,878	877,076	671,880	554,748	396,459	318,323
Iron Springs Solar QF	11,647,333	655,801	685,468	929,313	1,053,774	1,181,555	1,345,860	1,407,586	1,386,454	1,045,621	845,312	596,248	514,342
Kennecott Refinery QF	203,795	-	-	30,183	21,143	34,175	31,171	25,160	21,738	10,750	-	11,552	17,921
Kennecott Smelter QF	1,081,247	46,820	85,692	97,294	50,193	92,229	132,692	204,703	158,074	100,678	-	54,555	58,317
Latigo Wind Park QF	9,670,784	1,007,477	917,570	1,126,955	893,263	860,620	745,979	668,253	572,323	616,686	799,252	709,690	752,715
Mountain Wind 1 QF	9,355,354	1,464,332	1,095,022	918,677	715,713	509,895	525,547	398,455	469,761	412,814	780,902	955,656	1,108,581
Mountain Wind 2 QF	14,379,185	2,110,066	1,620,157	1,398,474	1,102,046	788,661	936,708	727,753	762,313	690,068	1,150,635	1,473,964	1,618,341
North Point Wind QF	16,733,095	1,104,918	1,536,422	1,492,136	1,473,588	1,045,561	1,061,127	1,318,716	1,389,273	1,399,663	1,545,725	1,705,440	1,660,527
Oregon Wind Farm QF	12,154,347	728,223	945,568	1,113,158	1,292,005	1,254,451	1,221,012	1,200,933	1,076,661	846,318	742,352	871,289	862,376
Pavant II Solar QF	3,324,534	137,284	171,222	278,384	323,737	354,706	341,329	423,049	415,201	325,714	263,613	160,801	129,497
Pioneer Wind Park I QF	10,641,406	1,305,428	926,029	1,189,660	901,601	709,426	649,524	650,952	683,005	451,955	820,623	1,259,004	1,094,200
Power County North Wind QF	4,800,686	366,034	483,048	463,144	452,207	314,979	310,432	331,248	307,411	330,458	458,196	454,287	529,240
Power County South Wind QF	4,371,173	328,366	431,748	424,900	426,383	276,795	280,912	289,475	290,447	300,576	402,367	436,258	482,947
Spanish Fork Wind 2 QF	2,701,900	207,568	166,728	196,191	154,639	148,333	207,958	301,062	334,188	272,207	240,410	243,600	229,017
Sunnyside QF	29,289,731	2,595,942	2,404,679	2,572,826	1,739,373	2,586,256	2,503,978	2,582,000	2,509,209	2,541,506	2,157,434	2,498,367	2,598,160
Tesoro QF	788,897	32,735	78,584	116,100	81,928	84,068	60,968	50,868	53,520	46,939	48,259	58,766	76,162
Three Peaks Solar QF	8,719,753	422,444	485,885	642,764	857,051	892,860	944,180	1,080,614	1,049,186	822,132	690,742	453,714	378,182
Utah Pavant Solar QF	4,047,713	151,429	195,080	330,092	358,347	401,177	452,058	542,053	519,133	412,016	318,907	205,863	161,560
Utah Red Hills Solar QF	11,814,347	495,290	632,485	806,680	1,052,941	1,235,075	1,271,771	1,556,476	1,509,740	1,352,537	828,567	600,728	472,057
Qualifying Facilities Total	320,221,358	23,732,523	23,850,447	27,677,809	27,998,544	29,230,816	29,817,429	30,834,720	30,194,292	26,689,724	24,447,391	23,012,724	22,734,939
Mid-Columbia Contracts													
Douglas - Wells	3,699,695	306,008	306,008	306,008	306,008	306,008	306,008	306,008	306,008	312,909	312,909	312,909	312,909
Grant Reasonable	(1,372,189)	(114,349)	(114,349)	(114,349)	(114,349)	(114,349)	(114,349)	(114,349)	(114,349)	(114,349)	(114,349)	(114,349)	(114,349)
Grant Surplus	2,030,780	169,232	169,232	169,232	169,232	169,232	169,232	169,232	169,232	169,232	169,232	169,232	169,232
Mid-Columbia Contracts Total	4,358,286	360,890	360,890	360,890	360,890	360,890	360,890	360,890	360,890	367,791	367,791	367,791	367,791
Total Long Term Firm Purchases	495,541,889	41,479,909	38,581,483	43,772,229	42,533,879	42,362,434	43,194,145	43,376,983	42,463,213	38,881,065	39,337,604	39,706,117	39,852,828

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Net Power Cost Analysis

12 months ended December 2017	01/17-12/17	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Storage & Exchange													
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	13,985,540	4,657,370	4,399,320	4,928,850	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	13,985,540	4,657,370	4,399,320	4,928,850	-	-	-	-	-	-	-	-	-
System Balancing Purchases													
COB	19,671,163	902,071	1,279,628	1,853,372	2,545,861	1,758,055	2,758,594	2,027,636	3,009,967	1,480,976	528,296	535,434	991,273
Four Corners	16,149,664	976,066	1,519,601	1,804,325	1,543,230	893,187	1,162,875	1,754,219	2,338,369	673,906	1,117,470	1,170,551	1,195,864
Mead	6,829,226	781,215	923,656	732,808	296,252	561,272	279,215	1,034,993	642,435	252,718	413,365	559,653	351,644
Mid Columbia	57,934,016	3,762,261	1,742,540	3,678,281	7,145,015	12,254,626	5,212,081	9,255,950	5,489,273	2,287,352	3,026,583	1,398,254	2,681,801
Mona	9,756,448	304,366	1,022,042	2,450,861	287,190	575,749	293,568	269,247	897,245	398,919	278,792	1,706,667	1,271,803
NOB	2,784,458	21,215	272,067	-	83,797	148,170	987,118	728,270	275,384	6,306	-	81,399	180,732
Palo Verde	38,177,123	9,877,438	8,594,543	8,371,804	806,785	1,372,806	1,098,588	1,845,508	1,991,462	1,127,977	845,169	299,121	1,945,921
EIM Imports	(5,263,030)	(532,167)	(532,167)	(532,167)	(532,167)	(532,167)	(251,424)	(251,424)	(251,424)	(251,424)	(532,167)	(532,167)	(532,167)
Emergency Purchases	72,526	842	-	742	-	-	-	46,576	11,341	-	13,026	-	-
Total System Balancing Purchases	146,111,594	16,093,306	14,821,910	18,360,025	12,175,964	17,031,699	11,540,616	16,710,976	14,404,052	5,976,730	5,690,533	5,218,913	8,086,871
Total Purchased Power & Net Interc	661,039,023	62,680,585	58,252,714	67,511,104	55,159,843	59,844,133	55,184,761	60,537,958	57,317,264	45,307,795	45,478,138	45,375,030	48,389,700

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_Cum ORTAM17 NPC Study_2016 07 30 CONF

Net Power Cost Analysis

12 months ended December 2017	01/17-12/17	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Wheeling & U. of F. Expense													
Firm Wheeling	144,232,139	11,627,114	11,842,313	12,119,407	11,470,653	11,194,729	12,116,632	12,553,679	11,210,330	11,426,439	12,856,065	13,479,297	12,335,480
C&T EIM Admin fee	1,318,331	109,729	109,650	109,730	109,980	110,100	110,119	109,861	109,861	109,861	109,861	109,761	109,818
ST Firm & Non-Firm	22,282	4,607	3,970	951	120	3,806	642	151	1,326	202	-	1,652	4,854
Total Wheeling & U. of F. Expense	145,572,752	11,741,450	11,955,933	12,230,089	11,580,752	11,308,636	12,227,393	12,663,691	11,321,518	11,536,502	12,965,926	13,590,710	12,450,152
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	54,030,506	5,044,108	4,641,258	4,932,301	4,131,278	3,154,837	3,748,413	5,080,782	4,908,500	4,774,809	4,579,604	4,771,198	4,263,417
Colstrip	16,262,041	1,462,056	1,383,276	1,145,890	1,077,112	1,519,252	1,482,045	862,481	1,493,088	1,455,134	1,509,348	1,400,357	1,472,002
Craig	28,208,991	2,514,375	2,115,482	2,488,134	1,942,852	2,522,767	2,453,523	1,921,716	2,484,145	2,444,339	2,473,683	2,284,947	2,563,026
Dave Johnston	56,536,617	4,419,865	4,425,955	3,783,622	4,393,604	5,068,706	5,077,715	5,043,282	5,327,477	5,075,180	4,887,902	4,478,787	4,554,521
Hayden	11,796,661	1,129,190	1,036,772	1,109,503	888,435	952,175	973,107	1,241,633	1,282,645	793,904	469,106	856,909	1,063,283
Hunter	159,719,030	13,497,033	11,949,885	10,885,414	11,212,743	13,044,657	13,491,888	14,732,206	14,284,313	13,427,234	14,477,829	13,930,788	14,785,041
Huntington	132,405,902	11,833,994	9,098,433	12,328,616	10,443,417	11,261,581	10,561,828	11,381,373	12,065,677	10,987,589	9,511,609	10,329,935	12,601,851
Jim Bridger	229,253,312	23,148,621	20,451,179	19,603,484	13,775,066	14,785,239	15,812,019	19,978,582	21,275,850	18,857,043	19,496,550	20,447,622	21,622,057
Naughton	101,271,217	9,417,757	7,695,428	9,083,868	6,408,481	6,359,974	8,079,954	9,455,307	9,245,501	8,708,879	8,821,439	8,961,201	9,033,429
Wyodak	29,135,514	1,950,370	2,038,753	2,633,248	2,468,377	2,614,652	2,525,809	2,701,022	2,358,857	2,540,676	2,538,916	2,235,181	2,529,654
Total Coal Fuel Burn Expense	818,619,792	74,417,369	64,836,421	67,994,080	56,741,365	61,283,841	64,206,301	72,398,385	74,726,052	69,064,786	68,765,986	69,696,926	74,488,281
Gas Fuel Burn Expense													
Chehalis	42,685,733	2,505,146	1,475,143	745,287	4,993,949	3,194,549	3,361,366	6,717,240	4,759,690	5,892,220	5,340,110	1,373,030	2,328,002
Currant Creek	28,445,637	2,355,515	1,418,521	1,410,541	658,425	133,343	2,021,425	5,240,550	5,439,912	3,583,583	1,525,678	1,440,193	3,217,952
Gadsby	2,019,379	-	-	-	-	-	-	990,287	1,029,092	-	-	-	-
Gadsby CT	1,425,095	25,990	1,858	-	-	-	68,066	514,894	510,196	115,924	92,936	25,662	69,568
Hermiston	33,943,539	3,921,623	3,203,827	2,823,154	1,165,132	34,338	2,089,636	3,337,023	3,570,638	3,513,716	2,849,253	3,560,832	3,874,367
Lake Side 1	57,675,596	6,086,732	2,810,067	4,363,511	3,474,745	3,142,607	3,294,966	6,349,291	7,363,074	6,190,405	3,148,713	5,493,079	5,958,405
Lake Side 2	71,457,094	6,966,936	4,667,572	5,026,180	3,802,265	4,300,277	5,499,165	7,476,715	7,906,087	7,212,160	6,222,657	5,721,876	6,655,203
Naughton - Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	237,652,073	21,861,943	13,576,989	14,368,674	14,094,516	10,805,115	16,334,624	30,625,999	30,578,689	26,508,008	19,179,347	17,614,673	22,103,496
Gas Physical	(33,750)	(11,625)	(10,500)	(11,625)	-	-	-	-	-	-	-	-	-
Gas Swaps	11,617,023	123,613	224,000	1,493,503	1,372,125	1,477,073	1,363,125	1,062,680	1,006,028	1,017,300	950,228	949,200	578,150
Clay Basin Gas Storage	(174,762)	(190,370)	(183,035)	(131,267)	52,242	52,242	52,242	52,242	52,242	52,242	52,242	5,280	(41,067)
Pipeline Reservation Fees	35,987,710	3,018,853	2,879,658	3,017,812	2,971,736	3,017,812	2,974,939	3,056,877	3,057,530	2,976,983	3,021,971	2,972,901	3,020,638
Total Gas Fuel Burn Expense	285,048,294	24,802,414	16,487,112	18,737,096	18,490,619	15,352,242	20,724,930	34,797,799	34,694,488	30,554,534	23,203,788	21,542,054	25,661,216
Other Generation													
Blundell	4,416,891	414,558	380,270	413,155	370,130	388,614	346,219	364,058	381,060	344,013	255,097	381,896	377,821
Blundell Bottoming Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-
Integration Charge	7,546,940	661,279	583,876	707,556	663,057	664,050	651,401	606,458	583,636	554,306	612,218	631,820	627,282
Total Other Generation	11,963,831	1,075,837	964,145	1,120,711	1,033,187	1,052,664	997,620	970,516	964,696	898,319	867,315	1,013,716	1,005,103
Net Power Cost	**1,553,390,530**	133,904,894	121,610,464	127,526,030	119,178,317	125,532,026	129,341,791	153,006,049	145,504,527	122,289,222	120,403,637	122,068,608	133,024,965
Net Power Cost/Net System Load	**25.65**	**24.89**	**25.58**	**25.83**	**25.90**	**25.88**	**26.13**	**26.78**	**26.26**	**25.28**	**25.44**	**25.05**	**24.68**

Docket No. UE 307
Exhibit PAC/403
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

Corrections and Updates Summary Reply Filing 2017

August 2016

Oregon TAM 2017 (April 2016 Initial Filing)		**NPC ($) =**	**1,566,031,929**
		$/MWh =	**25.86**

Corrections		**Impact ($)**	**NPC ($)**
C01 - EIM PGE (Portland General Electric) Benefit		(111,862)	
C02 - EIM Margin Benefit		(4,420,985)	
C03 - EIM CCA Prices		1,583	
	Total Corrections =	(4,531,264)	
Accepted Adjustments			
A01 - Remove NPC Impact of Jim Bridger 3&4 SCRs		(1,624,495)	
Updates			
U01 - Douglas Public Utility District Pro-forma		(21,655)	
U02 - QF Contract Status		(1,136,461)	
U03 - Black Hills Sale Fixed and Variable Charges		94,250	
U04 - Colstrip Transmission		155,332	
U05 - Pipeline Updates		(75,756)	
U06 - Wheeling Updates		(493,291)	
U07 - Official Forward Price Curve and Short Term Firm Transactions		14,655,102	
U08 - Coal Cost		(10,775,910)	
U09 - EIM Benefits		(9,402,212)	
	Total Updates =	(7,000,600)	
	System balancing impact of all adjustments	514,960	
	Total Change from April 2016 Initial Filing	(12,641,399)	
	Oregon TAM 2017 (July 2016 Filing)	**NPC ($) =**	**1,553,390,530**
		$/MWh =	**25.65**

Docket No. UE 307
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Exhibit Accompanying Reply Testimony of Brian S. Dickman

Other Revenue Reply Filing 2017

August 2016

PacifiCorp
CY 2017 TAM
Other Revenues - Stand Alone TAM Adjustment

Line no		Total Company UE-296 Final	Total Company CY 2017 Initial	Total Company CY 2017 Reply	Factor	Factors CY 2016	Factors CY 2017	Oregon Allocated UE-296 Final	Oregon Allocated CY 2017 Initial	Oregon Allocated CY 2017 Reply
1	Seattle City Light - Stateline Wind Farm	(9,811,103)	(9,749,394)	(9,749,394)	SG	25.464%	25.230%	(2,498,269)	(2,459,805)	(2,459,805)
2	Non-company owned Foote Creek	(904,184)	(900,686)	(905,359)	SG	25.464%	25.230%	(230,239)	(227,246)	(228,425)
3	BPA South Idaho Exchange	(4,691,490)	-		SG	25.464%	25.230%	(1,194,627)	-	-
4	Little Mountain Steam Revenues	-	-		SG	25.464%	25.230%	-	-	-
5	James River Royalty Offset	-	-		SG	25.464%	25.230%	-	-	-
6										-
7	Total Other Revenue	(15,406,778)	(10,650,079)	(10,654,753)				(3,923,135)	(2,687,051)	(2,688,230)
8										
9	Decrease (Increase) in Other Revenues Absent Load Change								1,236,084	1,234,905
10										
11	Baseline Other Revenues in Rates							(3,923,135)		
12	$ Change due to load variance from UE 296 CY 2016 forecast							67,809		
13	Other Revenues in Rates using 2017 load forecast							(3,855,326)		
14										
15	**Decrease (Increase) in Other Revenues Including Load Change**								**1,168,275**	**1,167,096**

Docket No. UE 307
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

EIM Costs Reply Filing 2017

August 2016

PacifiCorp
Oregon 2017 TAM
EIM Costs
Reply Update - Aug 1, 2016

Attachment OPUC 41

$ dollars

	CY 2017 EIM Costs 13 Month Average							
	Total Company			**Factor**	**Factors**	**Oregon Allocated**		
	2016 Final	**Initial Update**	**Reply Update**		**CY 2017**	**2016 Final**	**Initial Update**	**Reply Update**
Capital Investment	16,291,370	16,291,370	16,466,551	SG	25.230%	4,148,384	4,110,367	4,154,566
ADIT	(3,009,988)	(2,920,796)	(3,472,353)	SG	25.230%	(766,454)	(736,927)	(876,086)
Depreciation Reserve	(3,812,898)	(6,152,331)	(6,624,425)	SG	25.230%	(970,905)	(1,552,254)	(1,671,365)
Net Rate Base	9,468,484	7,218,243	6,369,773			2,411,026	1,821,187	1,607,115
	10.75%	10.75%	10.75%			10.75%	10.75%	10.75%
Pre-Tax Return on Rate Base	$ 1,018,231	$ 776,242	$ 684,999	SG	25.230%	$ 259,279	$ 195,849	$ 172,828
Operation & Maintenance (Ongoing)	1,264,222	1,942,499	1,833,600	SG	25.230%	321,918	490,099	462,624
Depreciation	2,339,433	2,339,433	2,367,987	SG	25.230%	595,706	590,247	597,451
Total Revenue Requirement	$ 4,621,885	$ 5,058,174	$ 4,886,586			$ 1,176,903	$ 1,276,194	$ 1,232,902
CAISO Fee in net power costs	$ 491,461	$ 1,269,231	$ 1,318,331	SG	25.230%	125,144	320,231	332,619
Total EIM Costs	$ 5,113,347	$ 6,327,406	$ 6,204,917			$ 1,302,047	$ 1,596,426	$ 1,565,521

Docket No. UE 307
Exhibit PAC/406
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

EIM Inter-Regional Benefits Reply Filing 2017

August 2016

PacifiCorp
Oregon - CY 2017 TAM
Inter-Regional EIM Benefits - CAISO, PacifiCorp, Nevada Energy

	6/1/2015	7/1/2015	8/1/2015	9/1/2015	10/1/2015	11/1/2015	12/1/2015	1/1/2016	2/1/2016	3/1/2016	4/1/2016	5/1/2016	Total
PACW to CAISO Exports													
Historical Export Volume (MWh)	120,639	127,861	87,325	61,418	43,936	54,756	74,204	61,255	84,342	97,306	82,337	52,332	947,713
Historical Export Volume (aMW)	168	172	117	85	59	76	100	82	121	131	114	70	108
Transmission Left Open MidC to COB (MWh)	197,266	156,426	137,941	130,399	185,106	165,758	193,435	205,369	190,363	215,811	230,237	229,125	2,237,235
Transmission Left Open MidC to COB (aMW)	274	210	185	181	249	230	260	276	274	290	320	308	255
Historical Export Margin	$ 1,808,047	$ 2,089,863	$ 1,290,923	$ 542,647	$ 316,420	$ 1,017,176	$ 707,939	$ 374,227	$ 501,991	$ 633,798	$ 455,793	$ 380,438	$ 10,119,261
Historical Export Margin ($/MWh Avail Trans)	$9.17	$13.36	$9.36	$4.16	$1.71	$6.14	$3.66	$1.82	$2.64	$2.94	$1.98	$1.66	
Adjustment for NVE Participation	47%	47%	47%	47%	47%	47%	100%	100%	100%	100%	100%	100%	
Adjusted Export Margin ($/MWh Avail Trans)	$4.32	$6.30	$4.41	$1.96	$0.81	$2.89	$3.66	$1.82	$2.64	$2.94	$1.98	$1.66	
Seasonal Export Margin ($/MWh Avail Trans)	$4.34	$4.34	$4.34	$4.34	$2.28	$2.28	$2.28	$2.28	$2.28	$2.28	$2.28	$2.28	
2017 TAM Available Transmission (MWh)	198,762	211,734	155,618	81,218	96,669	99,457	140,261	97,679	72,549	52,680	140,857	200,514	1,547,996
2017 TAM Export Margin	**$ 863,217**	**$ 919,555**	**$ 675,844**	**$ 352,727**	**$ 220,411**	**$ 226,769**	**$ 319,803**	**$ 222,714**	**$ 165,416**	**$ 120,113**	**$ 321,162**	**$ 457,185**	**$ 4,864,916**
CAISO to PACW Imports													
Import Volume (MWh)	7,236	5,800	7,790	8,805	11,356	17,126	18,408	34,075	17,528	11,559	11,343	27,872	178,898
Import Volume (aMW)	10	8	10	12	15	24	25	46	25	16	16	37	20
Historical Import Margin	$ 37,372	$ 27,276	$ 71,817	$ 93,800	$ 184,548	$ 63,872	$ 48,616	$ 81,428	$ 83,323	$ 63,651	$ 72,913	$ 69,247	$ 897,864
Adjustment for NVE Participation	68%	68%	68%	68%	68%	68%	100%	100%	100%	100%	100%	100%	
2017 TAM Import Margin	**$ 25,228**	**$ 18,413**	**$ 48,480**	**$ 63,320**	**$ 124,580**	**$ 43,117**	**$ 48,616**	**$ 81,428**	**$ 83,323**	**$ 63,651**	**$ 72,913**	**$ 69,247**	**$ 742,316**
PACE to NVE Exports													
Historical Export Volume (MWh)	-	-	-	-	-	-	38,263	50,036	48,494	45,394	40,342	29,141	251,670
Historical Export Volume (aMW)	-	-	-	-	-	-	51	67	70	61	56	39	57
Historical Export Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ 292,317	$ 432,377	$ 307,669	$ 675,122	$ 685,641	$ 212,382	$ 2,605,508
Historical Average Export Margin	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 5,211,017
Summer Adjustment	203%	203%	203%	203%									
2017 TAM Export Margin	**$ 881,962**	**$ 881,962**	**$ 881,962**	**$ 881,962**	**$ 434,251**	**$ 434,251**	**$ 434,251**	**$ 434,251**	**$ 434,251**	**$ 434,251**	**$ 434,251**	**$ 434,251**	**$ 7,001,859**
NVE to PACE Imports													
Import Volume (MWh)	-	-	-	-	-	-	50,538	66,998	67,133	90,983	126,718	135,162	537,532
Import Volume (aMW)	-	-	-	-	-	-	68	90	96	122	176	182	122
Historical Import Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ 236,354	$ 211,143	$ 230,511	$ 772,500	$ 810,506	$ 491,830	$ 2,752,844
Historical Average Import Margin	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 5,505,688
Summer Adjustment	46%	46%	46%	46%									
2017 TAM Import Margin	**$ 212,564**	**$ 212,564**	**$ 212,564**	**$ 212,564**	**$ 458,807**	**$ 458,807**	**$ 458,807**	**$ 458,807**	**$ 458,807**	**$ 458,807**	**$ 458,807**	**$ 458,807**	**$ 4,520,714**

Docket No. UE 307
Exhibit PAC/407
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

Staff Response to PacifiCorp Data Request 2

August 2016

UE 307/OPUC
July 19, 2016
PacifiCorp 1st Set of Data Requests

PacifiCorp Data Request 2:

Refer to Staff/200, Kaufman/11. Staff states, "The additional monthly and daily transactions needed should be a decreasing function of real-time transactions. That is, as less real-time transactions are needed, there is less of a need for additional balancing transactions to manage them."

a. Does Staff agree that the monthly and daily transactions are incurred to balance the Company's system before the real-time transaction period?

b. If the response to subpart (a) above is yes, does Staff agree that real-time transactions are the transactions prior to an hour used to balance the system, and the required volume of transactions will depend on everything transacted prior to that hour?

c. If the response to subpart (a) above is no, please explain why not.

Response to PacifiCorp Data Request 2:

a. Staff has not yet determined if any of PacifiCorp's actual monthly and daily transactions are incurred to balance the system. Staff has observed that some monthly and daily transactions are not made for system balancing. *See* PAC/100, Dickman/19 and Staff/200, Kaufman/12 at lines 15 – 19. The referenced statement was an evaluation of the Company's proposed rationale for additional balancing transactions as described in PAC/100, Dickman/16. It is Staff's position that PacifiCorp has not demonstrated in testimony that its actual behavior is consistent with the description in PAC/100, Dickman/16. Staff is continuing to analyze PacifiCorp transaction data to determine if monthly and daily transactions are performed for system balancing.

b. N/A.

c. See Staff's response to part a.

Docket No. UE 307
Exhibit PAC/408
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

Staff Response to PacifiCorp Data Request 12

August 2016

UE 307/OPUC
July 28, 2016
PacifiCorp 3rd Set of Data Requests

PacifiCorp Data Request 12

Refer to Staff/200, Kaufman/12:15-19. Mr. Kaufman states that "*Staff has also observed that a substantial volume of transactions are more appropriately categorized as either hedging transactions, where daily power is purchased several days to months ahead, or arbitrage transactions, where purchases and sales occur simultaneously at equal volumes of energy for identical delivery times.*"

a. Please identify all transactions where daily power is purchased more than three days in advance and which Staff considers to be more appropriately categorized as hedging transactions.
b. Please identify all transactions where purchases and sales occur simultaneously at equal volumes for identical delivery times and which Staff considers to be more appropriately categorized as arbitrage transactions.

Response to PacifiCorp Data Request 12

The requested data is provided in Confidential Attachment PAC 12a and Confidential Attachment PAC 12b. Staff relied on Dickman's confidential workpapers with file names beginning "STF" to generate the requested information.

a. Confidential Attachment PAC 12a contains PacifiCorp trades in which the variable "done_date" has a date more than three days before the variable "delivery_startdate". Staff assumes that "done_date" represents the date that the trade was made. Staff requested a description of each variable in the "STF" files in OPUC DR 29 c however this information was not provided. Staff notes that the data provided in the Dickman "STF" files do not include some long term transactions. The data also do not include non-firm transactions. Some of the excluded transactions may also have a trade date more than three days before the delivery date.
b. Confidential Attachment PAC 12b contains PacifiCorp trades that occur in matching pairs of purchases and sales, where a purchase of a specific MWh has a matching sale with the same MWh, "delivery_startdate", "delivery_stopdate", and "done_date". Staff does not claim that all trades represented in this file are arbitrage trades. For example, these data may contain pairs with purchase prices higher than sale prices. Staff also notes that the data may not represent all instances of arbitrage type trades. For example, matching purchases and sales performed one or more days apart, while including some component of speculation, may also be considered arbitrage.

   In addition, some transactions may be appropriately matched as arbitrage trading pairs that have differing MWh. For example, a purchase of 1000 MWh may reasonably be paired with a sale of 900 MWh, or two separate 500 MWh sales.

Docket No. UE 307
Exhibit PAC/409
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

REDACTED
Staff Response to PacifiCorp Data Request 4

August 2016

UE 307/OPUC
July 19, 2016
PacifiCorp 1st Set of Data Requests

PacifiCorp Data Request 4:

Refer to Staff/200, Kaufman/25. Staff argues that contract minimums should be ignored. Please provide calculations and workpapers quantifying the impact of the proposed adjustment based on the recommendation that the "Commission should reject the [artificial dispatch fuel cost adjustment] proposed by PacifiCorp."

Response to PacifiCorp Data Request 4:

Staff understands that PacifiCorp intends to file updates to its power cost forecast prior to November 2016. Staff's proposal is to replace the GRID inputs that are the result of the 2017 TAM model changes with GRID inputs as they were calculated in the 2016 TAM. Staff understands that in 2016 the relevant inputs were calculated as the marginal contract or spot price. *See* Staff/200, Kaufman/25, lines 9 – 12.

Staff has estimated a preliminary calculation of the cost decrease of [redacted]. Staff anticipates that this figure will change as the other power cost components are finalized. For supporting work papers see Attachment 4.

Docket No. UE 307
Exhibit PAC/410
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

CUB Response to PacifiCorp Data Request 1

August 2016

UE 307 / CUB
July 19, 2016
PacifiCorp Data Request 1

PacifiCorp Data Request 1

Refer to CUB/100, McGovern/9. Please identify the specific take or pay contracts and provide calculations and workpapers quantifying the impact of the proposed adjustment based on the recommendation that the "costs and impacts of the most recent take or pay contracts should be disallowed."

Response to Data Request 1

Regarding the specific contracts, CUB refers to its opening testimony and CUB Exhibit 102. Take-or-pay contracts that were signed on or after 2013, have not been demonstrated to be prudent, given that the Company was aware or environmental cost risk. Therefore, customers should not be burdened with implicit or explicit costs arising from any take or pay contracts that were signed 2013 or later.

CUB did not make a recommendation on a particular dollar adjustment, and therefore does not have workpapers to support said dollar adjustment. CUB's understanding is that the Company's current approach is to run the model twice-once with the contracted price of coal, and once with the cost of coal at zero--to find out whether the minimum take threshold is economical to trigger. Then, the Company manually implements this level and the inferred price. CUB also understands that the Company takes this approach because GRID cannot handle two simultaneous fuel prices for the Coal plant. CUB believes that the Company's approach is a manual alternative to the GRID model. Hence, CUB's recommendation is not that the Company make a dollar adjustment to its forecast, but, rather, CUB recommends that the Company re-run GRID with the minimum of market cost of coal or the contract price, and allow the model to optimize. Then, the corresponding optimal output, along with other model components will determine NVPC. CUB further notes that the impact of this adjustment will change as the Company further updates its power cost forecasts as this docket goes forward.

Docket No. UE 307
Exhibit PAC/411
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

CAISO Technical Bulletin
"Quantifying the Benefits of Participating in EIM"

August 2016

California ISO
Shaping a Renewed Future

TECHNICAL BULLETIN

Quantifying the Benefits for Participating in EIM

August 28, 2014

www.caiso.com | 250 Outcropping Way, Folsom, CA 95630 | 916.351.4400
Author: Lin Xu

Revision History

Date	Version	Description	Author
8/28/2014	1.0		Lin Xu

Note: *This technical bulletin is provided for the convenience of the market participant for the purpose of communicating complex and technical information. The technical bulletin is intended to be consistent with the ISO tariff, however, the ISO is bound to operate in accordance with the tariff in all cases. In the event there is any conflict between this technical bulletin and the ISO tariff, the ISO tariff will control. Any provision of the ISO tariff that may have been summarized or repeated in this technical bulletin is provided only to aid in the understanding of this technical bulletin and in no event shall any of the information in this technical bulletin be deemed an interpretation of the tariff, or in any way binding. While the ISO endeavors to update the information and analysis in this technical bulletin and to notify market participants of changes pertinent to this technical bulletin, it is the responsibility of each market participant to ensure that he or she is using the most recent version of this technical bulletin that it has not been retired or withdrawn, that the information in the technical bulletin is current, and to comply with all applicable provisions of the ISO's tariff. The market participant use of this technical bulletin, and all information contained herein, is at its sole risk.*

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Executive Summary

This paper proposes a systematic way to quantify each EIM region's benefits in terms of increased economic surplus, or cost saving. The EIM benefit is calculated by the dispatch cost difference between the EIM dispatch and a counterfactual without EIM dispatch. If there is energy transfer or flex ramp transfer between EIM regions, the cost of the transfer will be shifted from the supply region to the demand region. The counterfactual without EIM dispatch is obtained by rerunning the same EIM market clearing engine with modifications to mimic the pre EIM dispatch practice. The ISO will quantify the EIM benefits based on the fifteen-minute market, which will capture the majority of benefits. There are additional benefits in the 5-minute market, but the ISO does not plan to calculate the benefits on a 5-minute basis because the without EIM counterfactual "reruns" would consume extensive additional resources and complexity to simulate 288 RTD market runs daily. Calculating the benefits on a 15-minute basis reflects a conservative approach that may undervalue the true benefit. The ISO will conduct some test cases using both 15 minute and 5 minute intervals for the without EIM to estimate the additional 5-minute benefits.

Background

PacifiCorp and the California ISO have agreed to jointly create a real-time energy imbalance market (EIM) by October 2014. Following the October Go-live, EIM will be available to all Balancing Authorities (BA) in the West. The EIM will efficiently dispatch resources across multiple balancing authorities in real time to balance supply and demand, and is expected to reduce system costs, while also enhancing reliability. The EIM utilizes advanced optimization technology to dispatch resources, and encourages flexible resource participation via flexible capability compensation, which helps to accommodate more renewable generation. EIM participants can benefit from (1) more efficient dispatch of resources both within and between balancing authorities, and (2) the ability to share flexible resources to accommodate variable energy resources. A joint PacifiCorp/ISO study performed by the E3 consulting firm predicts EIM will create a benefit ranging from \$12 million to \$129 million in 2017.[1] Once EIM is implemented, the California will quantify EIM benefits of the participating EIM entities using real market data. This technical paper will outline the methodology that the ISO will use to quantify the EIM benefits.

The benefit of participating in EIM is measured by the economic surplus. Economic surplus, also known as total welfare or market efficiency, is the difference between consumers' willingness to pay and the producers' cost to produce. Economic surplus characterizes the net benefit of producing and consuming electric energy. If demand's willingness to pay is viewed as negative cost, economic surplus is equal to the absolute value of total dispatch cost. So we can also consider the EIM benefit as representing the cost savings. Participating in EIM may increase an EIM region's economic surplus, or save cost, because:

[1] PacifiCorp, Energy Imbalance Markets Summary,
http://www.pacificorp.com/content/dam/pacificorp/doc/About_Us/Energy_Imbalance_Market/6709-49_PC_EIM_Handout_8.5x11_r7.pdf

- additional transfers may clear economically between EIM regions, which let lower cost generation from one EIM region to meet demand in another EIM region with higher cost, and also help mitigate regional over generation or under generation risks,
- new participating resource that are not dispatched by the BA may be dispatched in EIM economically, which replaces more expensive generation,
- resources with EIM offers may be re-dispatched to reduce overloads on transmission paths and to reduce cost,
- real-time incremental load will be met economically subject to transmission limitations, and
- EIM may require less flexible ramping per region, and allow flexible ramping transfers between regions, which may reduce the overall procurement cost.

In order to calculate the magnitude of these possible benefits, we need to compare the economic surplus of the actual EIM dispatch with that of a counterfactual dispatch absent the EIM. The counterfactual dispatch without an EIM is obtained by re-clearing the market to meet the same load while respecting the same transmission constraints with the following modifications to mimic the pre EIM dispatch practice.

We will calculate the bid costs associated with the incremental and decremental dispatches between EIM and the without EIM counterfactual, and sum them up to be the total EIM benefit. We will also divide the total benefit into regions, so each BAA has its own calculated regional benefit.

Method

The method here will calculate the benefit of participating EIM for each EIM region, or BAA. The method requires EIM market clearing results, and the counterfactual clearing results from re-simulating the market clearing without EIM.

Counterfactual without EIM dispatch

The counterfactual without EIM dispatch is to mimic the pre EIM dispatch practice, where each BAA meets its own load and flex ramp without relying on real-time transfers or dispatching new participating resources. Specifically, the without EIM dispatch is obtained by rerunning the EIM market clearing engine with the following modifications.

- For all EIM regions:
    - disallow EIM transfers (beyond the base schedule transfers),
    - disallow flex ramp sharing and transfer between regions.
- For all EIM regions except CAISO:
    - fix the dispatch at the base schedule for each new participating resource,
    - if a resource list has been provided by an EIM BA identifying the resources they control and dispatch in real time pre EIM, limit the pool of dispatchable resources based on the provided list,
    - penalize deviations from base schedules by adding penalty cost of deviations to the objective function, so it results in the minimum sum of megawatt changes (absolute

values) in dispatching generation to eliminate overloads within the EIM created by base schedules, and prevents base schedules from clearing against each other.

By making these modifications, the counterfactual without EIM dispatch is expected to produce the following results:

- For all EIM regions:
  - No addition EIM transfers can be cleared.
  - Each region meets its own regional flex ramp requirement.
- For all EIM regions except CAISO:
  - New participating resources stays at the base schedule.
  - Base schedules cannot economically clear against each other.
  - Transmission overloads from base schedules are relieved by the most physically effective resources, not by the most economic resources.
  - Each non CAISO region's incremental real-time load from base schedules is met in economic merit order by supply from the same region that does not overload transmission paths.

These outcomes are consistent with how each BAA dispatch resources in real-time in response to system conditions changes pre EIM.

Energy and flex ramp transfer cost

Because the counterfactual without EIM dispatch maintains each region's independence, the change in the cost of the dispatch in one region will be attributable to meeting the load in the same region. However, that will not be the case in the EIM dispatch because EIM energy transfers and flex ramp transfers may raise cost in one region in order to reduce the cost of meeting load in another region. In this case, we have to shift the transfer cost from the exporting region to the importing region in order to correctly calculate each region's benefit from the EIM dispatch.

The energy transfer cost is the transfer MW times the average market clearing price of the transfer. If we use the convention that import MW is positive, and export MW is negative, then adding the transfer cost to each region will correctly shift cost in or out depending on weather it is import or export. The reason for using the average transfer price is that if the transfer constraint between two EIM regions is binding, the market clearing prices for the transfer are different on the source side and the sink side. In this case, we will use the average market clearing price, i.e. $0.5\left(LMP_{exp}^{EIM} + LMP_{imp}^{EIM}\right)$, to calculate the transfer cost. In doing this, any congestion rent over the tie lines will be split in half between the importing and exporting region. If the transfer constraint between the ISO and PAC is binding, then the transfer between the ISO and PAC has average price

$$0.5(LMP_{CAISO}^{EIM} + LMP_{PAC}^{EIM}) = LMP_{MALIN}^{EIM} + 0.5 \cdot SP_{CAISO-PAC}^{EIM}$$

which is the LMP at MALIN plus half of the shadow price of the transfer between the ISO and PAC. If the transfer constraint between the PACW and PACE is binding, then the transfer between the PACW and PACE has average price

$$0.5(LMP_{PACW}^{EIM} + LMP_{PACE}^{EIM}) = LMP_{HMWY}^{EIM} + 0.5 \cdot SP_{PACW-PACE}^{EIM}$$

which is the LMP at Hemingway plus half of the shadow price of the transfer between the PACW and PACE.

When PAC is exporting energy to CAISO, the total cost for the transfer also includes a Greenhouse Gas (GHG) cost[2]. Absent of intra region congestion, PAC will have two system wide LMPs. One LMP is the marginal cost to meet PAC internal load, and the other LMP is the marginal cost to meet CAISO load via the transfer. The LMP to meet CAISO load via the transfer is $LMP_{MALIN}^{EIM} + SP_{CAISO-PAC}^{EIM}$. The LMP to meet PAC load is $LMP_{MALIN}^{EIM} + SP_{CAISO-PAC}^{EIM} + SP_{CAISO-PAC}^{EIM,GHG}$, where $SP_{CAISO-PAC}^{EIM,GHG}$ is the GHG transfer constraint shadow price. Note that these transfer shadow prices are all less than or equal to zero. The export price for the transfer to do the EIM benefit calculation should be the LMP to meet CAISO load, i.e. $LMP_{MALIN}^{EIM} + SP_{CAISO-PAC}^{EIM}$. This is because the production cost in PAC already includes the GHG cost, and the LMP to meet CAISO also includes the GHG cost, so the difference between them will capture the benefit correctly. Therefore, with the GHG cost model, we will still calculate the ISO and PAC average price the same way, i.e.

$$\begin{aligned} 0.5(LMP_{exp}^{EIM} + LMP_{imp}^{EIM}) &= 0.5(LMP_{MALIN}^{EIM} + SP_{CAISO-PAC}^{EIM} + LMP_{MALIN}^{EIM}) \\ &= LMP_{MALIN}^{EIM} + 0.5 \cdot SP_{CAISO-PAC}^{EIM} \end{aligned}$$

For flex ramp, we also need to calculate the flex ramp transfer cost. The flex ramp transfer cost is equal to the allocated flex ramp cost minus the flex ramp supply payment in that region. The flex ramp supply market payment is equal to the sum of the flex ramp supply times the flex ramp market clearing price in that region. The allocated flex ramp cost is the flex ramp cost allocation to that region based on the ratio of individual regional requirement. The difference between them is the flex ramp transfer cost evaluated at the market clearing price.

For example, the system wide requirement is 100 MW, and the system wide flex ramp price is \$1. So the total flex ramp market payment is \$100. Region 1 supplied 70 MW, region 2 supplied 30 MW. The individual regional requirement is 60 MW per region. The \$100 total flex ramp market payment is allocated to the two regions equally based on the 60/60 ratio. For region 1, the flex ramp supply payment is \$70, and the allocated flex ramp cost is \$50. We will add \$50–\$70 = –\$20 to region 1's cost, which means region 1 is an exporting region, and we need to shift \$20 out of the region. Similarly, we will add \$50–\$30 = \$20 to region 2, which means region 2 is an importing region, and we need to shift \$20 into the region.

In summary, we will add transfer cost to each EIM region, and the transfer cost is calculated as follows:

[2] California ISO, energy imbalance market draft final proposal, https://records.oa.caiso.com/sites/MID/MIP/MDRP/Records/Initiatives/Full%20Network%20Model/2014-09-17_Pre-implementation%20analysis%20to%20Board/FNM_pre-implementation_analysis%20for%20BOG.docx

- for CAISO-PAC energy transfer, the transfer cost is equal to the transfer MW times $LMP^{EIM}_{MALIN} + 0.5 \cdot SP^{EIM}_{CAISO-PAC}$,
- for PACW-PACE energy transfer, the transfer cost is equal to the transfer MW times $LMP^{EIM}_{HMWY} + 0.5 \cdot SP^{EIM}_{PACW-PACE}$,
- for flex ramp transfer, the transfer cost is equal to allocated flex ramp cost minus total flex ramp supply payment in that region.

EIM benefit calculation steps

1. After EIM market clears, take the EIM savecase, create the counterfactual with the modifications for the without EIM case, and rerun the market with the same market clearing engine.
2. Calculate the difference between the EIM dispatch and the counterfactual dispatch, which will be referred as the delta dispatch.
3. Calculate the bid cost associated with the delta dispatch between the actual EIM dispatch and the counterfactual dispatch for each EIM region.
4. Calculate each region's energy transfer cost and flex ramp transfer cost.
5. Combine each region's delta dispatch costs and transfer costs to get the regional benefit.

Example

In this example, we will demonstrate how to apply the method to quantify the EIM benefits. The example is illustrated in Figure 1. The example consists of two EIM regions. Region 1 has only one generator G1. Region 1 represents the ISO. One can think of G1 is the excessive supply after meeting region 1's demand, and the balanced generation and loads in region 1 has been omitted for simplicity reason. Region 1 and region 2 are connected by a tie line A-B with 25 MW transfer capability. Region 2 has three buses and four generators. The three buses in region 2 are connected to each other by three transmission lines. Line D-B and line C-D all have large transfer capability, and will not be binding constraints. Line C-B's real time transfer capability is 50 MW, and it is likely to be a binding constraint. All the internal lines in EIM region 2 have equal impedances. EIM region 2, as a BA, owns G3, G4, and G5. G2 is a new participating resource in EIM region 2, which the BA does not dispatch pre EIM.

EIM region 2 has submitted balanced base schedules before going into real-time. G3, G4 and G5 supply 140 MW in total to meet load D1. Line C-B real time transfer capability is rated at 50 MW, which is over loaded by 10 MW by the base schedules (0*40+2/3*80+1/3*20=60 MW). EIM will correct this transmission overload. The energy bids and base schedules are listed in Table 1.

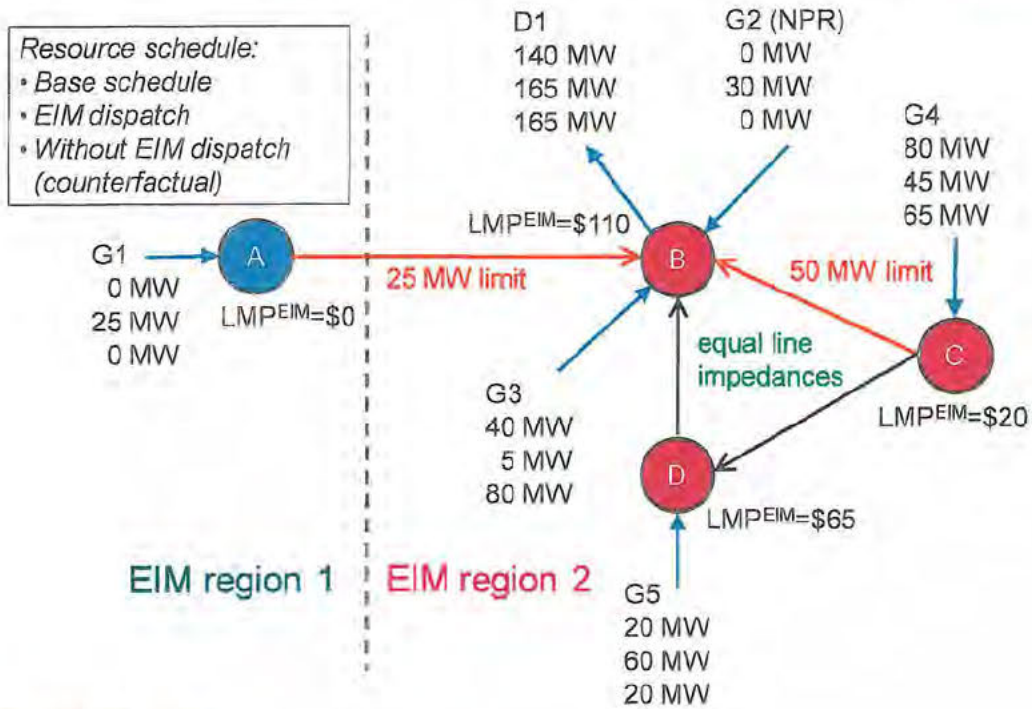

Figure 1: EIM example

One system change in EIM is that load increases by 25 MW from the load base schedule. G1 from region 1 and new participating resource G2 offer more economic supplies into EIM, and will change the market outcome. In addition, region 1 and region 2 each has regional flex requirement of 22 MW. The system wide flex ramp requirement is 40 MW, which is about 10% less the sum of the regional requirements 44 MW. The EIM schedules are listed in Table 1 and the flex ramp awards area listed in Table 2 with the following observations:

- An energy transfer of 25 MW from region 1 to region 2 is cleared, which has been limited by the transfer capability of A-B.
- New participating resource G2 is economically cleared to its Pmax 30 MW.
- Expensive base schedule on G3 is backed down to 5 MW. Had it not been a system wide flex ramp requirement of 40 MW, it should have been further backed down to 0 MW.
- G4 is dec'ed by 35 MW and G5 is inc'ed by 40 MW to relieve the congestion of 10 MW from base schedules, $-2/3*35+1/3*40 = -10$.
- Due to ramp rate limitation, G2, G3, G4 can provide 5 MW flex ramp each. G1 can provide 10 MW flex ramp from its dispatch 25 MW to its Pmax. G5's dispatch has to be withheld to free up capacity to provide the rest 15 MW of flex ramp, which incurs opportunity cost $5/MWh. The opportunity cost sets the system wide flex ramp price to $5/MWh.
- Region 2 supplies 30 MW of the flex ramp, and the 10 MW beyond its allocation 0.5*40=20 MW is a flex ramp transfer to region 1. Therefore, the flex ramp transfer cost from region 2 to region 1 is $50.

Res.	BAA	Type	Capacity	EIM bid price	Base sched	EIM sched	CF sched	Delta sched	Delta bid cost
G1	1	Gen	35	$0	0	25	0	+25	0
G2	2	NPR	30	$35	0	30	0	+30	1050
G3	2	Gen	90	$110	40	5	80	−75	−8250
G4	2	Gen	80	$20	80	45	65	−20	−400
G5	2	Gen	80	$60	20	60	20	+40	2400
D1	2	Load	N/A	$1000	−140	−165	−165	+0	0

Table 1: EIM and counterfactual without EIM dispatches

Res.	BAA	Type	Ramp capacity	EIM award	EIM price	EIM payment	EIM cost allocation	Transfer cost
G1	1	Gen	35	10	$5	$50	$100	$50
G2	2	NPR	5	0	$5	$0	$100	−$50
G3	2	Gen	5	5	$5	$25		
G4	2	Gen	5	5	$5	$25		
G5	2	Gen	40	20	$5	$100		
Tot.				40	$5	$200	$200	$0

Table 2: EIM flexible ramping awards and cost allocation

The without EIM schedules are obtained by rerunning the market clearing engine with the counterfactual modifications. The results are shown in Figure 1 and Table 1. As expected, the following results are observed:

- EIM transfer from region 1 to region 2 does not clear.
- New participating resource G2 stays at base schedule.
- Transmission overload from base schedules on C-B are relieved by inc'ing G3 by 15 MW and dec'ing G4 by 15 MW, which relieves 10 MW of overloads with 2/3 effectiveness. One can verify the other dispatches are less effective. Inc'ing G5 and dec'ing G3 has 1/3 effectiveness. Inc'ing G5 and dec'ing G4 also has 1/3 effectiveness.

- Region 2's incremental 25 MW load is met by G3 as it is the only resource to inc without further overloading C-B.
- Each region has a flex ramp requirement of 22 MW. G1 has 35 MW flex ramp supply, so flex ramp is not binding in region 1. In region 2, G3 and G4 have 5 MW flex ramp supply each, and G5 has 40 MW flex ramp supply, so the flex ramp is not binding in region 2 either.

Now we can calculate each region's EIM benefit. The EIM benefit for region 1 is calculated in Table 3, where we have calculated the energy transfer cost of the –25 MW transfer at average transfer price \$55/MWh. The average transfer price is the average LMP of LMP_A=\$0 and LMP_B=\$110 in EIM. We have also calculated a flex ramp transfer cost \$50, which is the cost of flex ramp incurred in region 2 to meet region 1's allocation. The regional benefit for region 1 is cost saving of \$1325. As a convention, negative benefit number represents a cost saving in the table.

The EIM benefit for region 2 is calculated in Table 4, where we have added a 25 MW of importing energy transfer at cost \$55/MWh. We have also calculated a flex ramp transfer cost –\$50, which is to shift out the cost of flex ramp incurred in region 2 to meet region 1's requirement. The regional benefit for region 2 is cost saving of \$3875. The total system EIM benefit is 1375+3825 = \$5200.

The congestion rent on A-B is 110*25 = 2750. We can see half of it goes to region 1's benefit as the transfer cost, so the othe half stays in region 2.

Res.	BAA	Type	EIM bid price	EIM sched	CF sched	Delta sched	Delta bid cost
G1	1	Gen	\$0	25	0	+25	0
ET-exp	1	En Transfer	\$55	–25	0	–25	–1375
RT-imp	1	Flex ramp Transfer					50
Total	1	BAA		0	0	0	–1325

Table 3: EIM benefit for region 1

Res.	BAA	Type	EIM bid price	EIM sched	CF sched	Delta sched	Delta bid cost
G2	2	NPR	$35	30	0	+30	1050
G3	2	Gen	$110	5	80	–75	–8250
G4	2	Gen	$20	45	65	–20	–400
G5	2	Gen	$60	60	20	+40	2400
D1	2	Load	$1000	–165	–165	0	0
ET-imp	**2**	**En transfer**	**$55**	**25**	**0**	**+25**	**1375**
RT-exp	**2**	**Flex ramp Transfer**					**–50**
Total	2	BAA		0	0	0	-3875

Table 4: EIM benefit for region 2

Docket No. UE 307
Exhibit PAC/412
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

CAISO 2016 Q1 Report "Benefits for Participating in EIM"

August 2016

Benefits for Participating in EIM

April 30, 2016

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Executive Summary

This is the "Quantifying EIM Benefits" report for the first quarter of 2016. The estimated gross benefits for January, February and March 2016 are $18.90 million. This brings the EIM total benefits to $64.60 million since it expanded the real-time market to balancing areas outside the California ISO.

The total gross benefits for Q1 2016 increased significantly from the past with the addition of NV Energy (NVE). This growth reflects the economic value associated with the increase in inter-regional transfer capability.

The benefit calculation method is described in a separate document.[1] This analysis demonstrates the EIM's ability to select the most economic resources across the PacifiCorp, NVE and ISO balancing authority areas (BAAs) that comprise the EIM footprint. The benefits quantified in this report fall into three categories and were described in earlier studies.[2]

- ***More efficient dispatch, both inter- and intra-regional, in the Fifteen-Minute Market (FMM) and Real-Time Dispatch (RTD),*** by automating dispatch every fifteen minutes and every five minutes within and across the EIM footprint, including the California ISO, PacifiCorp, and NV Energy.

- ***Reduced renewable energy curtailment,*** by allowing balancing authority areas to export or reduce imports of renewable generation when they would otherwise need to be economically curtailed, and

- ***Reduced flexibility reserves needed in all balancing authority areas,*** which saves cost by aggregating the load, wind, and solar variability and forecast errors of the combined EIM footprint. This report quantifies the diversity benefits of flexibility reserves for the entire EIM footprint.

Table 1 shows the estimated gross benefits summary for the first quarter of 2016 in millions of dollars per EIM entity.

Region	January	February	March	Total
CAISO	1.97	1.19	3.18	**6.35**
NV Energy	0.34	0.75	0.62	**1.70**
PacifiCorp	2.21	4.95	3.69	**10.85**
Total	**4.53**	**6.89**	**7.49**	**18.90**

[1] EIM Quarterly Benefit Report Methodology, https://www.caiso.com/Documents/EIM_BenefitMethodology.pdf. This report includes one enhancement to allow commitment of ISO short start units in the counterfactual dispatch.
[2] PacifiCorp-ISO, Energy Imbalance Markets Benefits, http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf

Table 1: Estimated gross benefits shown are in millions and accrued in the first quarter of 2016

One of the significant contributions to the EIM benefits are transfers across the balancing areas which provide lower supply cost, even while factoring in the cost of compliance with greenhouse gas (GHG) emissions cost when it is transferring into the ISO. As such, the transfer volumes are a good indicator of a portion of the benefits attributed to the EIM. Transfers can take place in both the Fifteen Minute Market (FMM) and Real-Time Dispatch (RTD). Generally, the transfer limits are based on transmission rights and interchange rights that participating balancing authority areas make available to EIM, with the exception of the PACW-ISO transfer limit in RTD. The RTD transfer capacities between PACW and the ISO are dynamically determined based on the allocated dynamic transfer capability driven by system operating conditions. This report does not quantify a BAA's opportunity cost that the utility considered when using its transfer rights for the EIM.

Balancing authority areas may submit base scheduled transfers. These transactions occurred between NVE and PACE. The EIM inter-regional benefits are calculated based on the transfer difference between the EIM and the base schedule. This is because the benefits associated with base scheduled transfers, to the extent that they exist, should be attributed to decisions made prior to the EIM, not to the economic efficiencies gained through the EIM.

While market conditions will vary, the EIM continues to provide benefits to participating entities and their customers as demonstrated in this report.

Background

The EIM began financially-binding operation on November 1, 2014 by optimizing resources across the ISO and PacifiCorp BAAs, which includes portions of California, Oregon, Washington, Utah, Idaho and Wyoming. NV Energy, operating in Nevada, began participating in December 2015. The EIM facilitates renewable resource integration and increases reliability by sharing information between balancing authorities on electricity delivery conditions across the EIM region. The ISO started publishing quarterly EIM benefit reports in January 2015. As other BAAs join the EIM, this report will expand to include the benefits associated with their participation.

EIM Benefits in Q1 2016

Table 1 breaks out the estimated EIM gross benefits by each BAA per month. The savings presented in the table show $4.53 million for January, $6.89 million for February, and $7.49 million for March. The increase of EIM benefit from month to month may be driven by variations in supply and demand.

Inter-regional Transfers

One of the significant contributions to the EIM benefits is transfers across the balancing areas which provide lower supply cost. Table 2 provides the 15-minute EIM transfer volume and the 5-minute EIM transfer volume, both with base schedule transfer excluded. NVE and PACE had submitted base schedule transfers. The EIM benefit is only attributable the transfers that occurred with EIM, but not the base schedules submitted prior to the EIM.

The transfer from BAA_x to BAA_y and the transfer from BAA_y to BAA_x are separately reported. For example, in an interval, if there is 100 MWh transfer on top of base transfer from CISO to NEVP, it will be reported as 100 MW with from_BAA=CISO and to_BAA=NEVP, and it will be reported as 0 MW with from_BAA=NEVP and to_BAA=CISO in the opposite direction. The 15-minute transfer volume results from EIM optimization in the 15-minute market with all bids and base schedules submitted into EIM. The 5-minute transfer volume results from EIM optimization in the 5-minute market with all bids and base schedules submitted into EIM, and unit commitments determined in the 15-minute market optimization.

NV Energy's EIM benefits mainly reflect inter-regional transfer benefits resulting from intra-hour transactions. This is attributed to NV Energy's optimization of its base schedules prior to submission to the EIM.

The ISO exported a significant amount of energy to NV Energy and PacifiCorp in this quarter. This compares to past quarters when the ISO had been mainly an importer. It is also worth noting that a significant level of energy that was exported by the ISO consisted of renewable generation.

Year	Month	from_BAA	to_BAA	15m EIM transfer (15m - base)	5m EIM transfer (5m - base)
2016	January	CISO	NEVP	100,643	69,845
2016	January	CISO	PACW	31,606	34,024
2016	January	NEVP	CISO	48,895	93,833
2016	January	NEVP	PACE	84,902	65,572
2016	January	PACE	NEVP	36,387	51,786
2016	January	PACE	PACW	39,612	58,139
2016	January	PACW	CISO	59,035	60,965
2016	February	CISO	NEVP	70,729	75,587
2016	February	CISO	PACW	15,617	17,377
2016	February	NEVP	CISO	69,461	92,008
2016	February	NEVP	PACE	62,732	65,937
2016	February	PACE	NEVP	48,928	49,354
2016	February	PACE	PACW	26,490	43,735
2016	February	PACW	CISO	74,595	83,854
2016	March	CISO	NEVP	136,887	139,781
2016	March	CISO	PACW	11,347	11,413
2016	March	NEVP	CISO	49,315	79,251
2016	March	NEVP	PACE	95,008	88,972
2016	March	PACE	NEVP	38,034	46,286
2016	March	PACE	PACW	9,278	23,291

2016	March	PACW	CISO	93,571	97,051
There is no PACW to PACE transfer capability					

Table 2: Energy transfers (MWh) in the FMM and RTD for the first quarter of 2016

Reduced Renewable Curtailment

The EIM helps avoid renewable curtailments within the ISO, which has both economic and environmental benefits. The EIM benefit calculation includes the economic benefits that can be attributed to avoided renewable curtailment within the ISO. If not for energy transfers facilitated by the EIM, some renewable generation located within the ISO would have been curtailed via either economic or exceptional dispatch. The total avoided renewable curtailment volume in MWh for Q1 2016 was calculated to be 17,261 MWh (January) + 41,287 MWh (February) + 54,399 MWh (March) = 112,948 MWh total. The energy being exported by the ISO included a significant level of renewable generation.

The environmental benefits of avoided renewable curtailment are significant. Under the assumption that avoided renewable curtailments displace production from other resources at a default emission rate of 0.428 metric tons CO_2/MWh, avoided curtailments displaced an estimated 48,342 metric tons of CO_2 for Q1 2016. Avoided renewable curtailments may also have reduced the volume of renewable credits that would have been retracted. However, this report does not quantify the additional value in dollars associated with this benefit.

Flexible ramping procurement diversity savings

The EIM facilitates procurement of flexible ramping capacity in the FMM to address variability that may occur in the RTD. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAA's requirement. This difference is known as the flexible ramping procurement diversity savings. Starting in March 2015, the ISO implemented an automated tool to analyze historical uncertainties and calculate the flexible ramping requirement for each BAA in the EIM. In Q1 2016, the flexible ramping requirement for the ISO varied from 300 MW to 500 MW, the requirement for PACE varied from 80 MW to 150 MW, the requirement for PACW varied from 60 MW to 100 MW, and the requirement for NVE varied from 80 MW to 100 MW. Due to the reduction in flexible ramping requirement associated with the larger EIM footprint, the total requirement across the four BAAs varied from 300 MW to 530 MW.

The flexible ramping procurement diversity savings for all the intervals averaged over a month are listed in Table 3. The percentage saving is the average MW savings divided by the sum of the four individual BAA requirements.

	January	February	March
Average MW saving	255	261	265
Sum of BAA requirements	758	752	753
Percentage savings	34%	35%	35%

Table 3: Flexible ramping procurement diversity saving for the first quarter of 2016

Under the current flexible ramping constraint design, the procured flexible ramping capacity can be fully accessed in RTD. If the flexible ramping procurement in the FMM is beneficial, it will reduce the RTD dispatch cost. With the EIM benefits being quantified on a 5-minute level, the benefit of flexible ramping is fully captured in the RTD dispatch. The EIM benefits calculated at a 5-minute level includes the savings from procuring and deploying flexible ramping. However, this analysis does not breakout the dollar savings separately because the savings are tightly integrated with the RTD dispatch.

Conclusion

The EIM continued to show significant benefits during the first quarter of 2016. The total benefits for the quarter of $18.90 million are consistent with pre-launch studies, and reflect the transfer benefits of a more robust EIM footprint, that includes both PacifiCorp and NV Energy.

Docket No. UE 307
Exhibit PAC/413
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

CUB Response to PacifiCorp Data Request 7

August 2016

UE 307 / CUB
July 19, 2016
PacifiCorp Data Request 7

PacifiCorp Data Request 7

Refer to CUB/100, McGovern/17. Referring to CUB's confidential exhibit 109, CUB states, "the Company seems to subtract the difference between COB and EIM prices as a lost opportunity cost."

a. Please provide specific reference within CUB exhibit 109 wherein COB market prices are contained.

Response to PacifiCorp Data Request 7

CUB finds this question confusing. Exhibit 109 is the Company's response to Staff's DR 42. The Company would have the best knowledge as to all the locations of COB market prices. However, in the Daily summary Column M, the Company incorporates lost opportunity. Moreover, in Hourly Summary Tab, column K, the Company lists "Lost opportunity Mid-C to COB". CUB in conversations with Staff and the Company attempted to decipher how the lost opportunity is being calculated and where it was utilized. CUB believes, after reviewing the Company's data response to Staff DR 42 on EIM benefits and costs, that lost opportunity costs are being incorporated into the Company's EIM benefit calculations. However, the Company's response to Staff DR 42 contains many incomplete references and broken cells that rely on workpapers not provided in the response.

Finally CUB notes that in testimony, CUB states that the Company seems to incorporate opportunity costs into the EIM cost approach, and that CUB believes the appropriate methodology would not include this. CUB seeks clarification on the Company's approach to this issue.

b. Does CUB agree that the 'Export Benefit excluding Lost Opportunity & Fees' calculated in CUB exhibit 109 is the sum of the fields Export $, Energy Cost, Variable O&M, and GHG cost (Columns C through F)? If so, please explain where CUB believes difference between COB and EIM prices is being subtracted out in the calculation of the EIM benefits?

Please refer to response 9a above.

Docket No. UE 307
Exhibit PAC/500
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Dana M. Ralston

August 2016

REPLY TESTIMONY OF DANA M. RALSTON

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ATTACHED EXHIBITS

Exhibit PAC/501 – PacifiCorp Compliance Proposal for Periodic Long-Term Fuel Plans

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Q. Are you the same Dana M. Ralston who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. My testimony addresses three issues. First, I describe the Company's updated coal costs in the Transition Adjustment Mechanism (TAM) Reply Update.

Second, I respond to the Opening Testimony filed by Public Utility Commission of Oregon (Commission) Staff (Staff) witness Mr. Lance Kaufman and Industrial Customers of Northwest Utilities' (ICNU) witness Mr. Bradley G. Mullins on July 8, 2016, proposing adjustments to the cost of coal from the Bridger Coal Company (BCC). Company witness Mr. R. Bryce Dalley also responds to the policy and ratemaking issues raised by these adjustments.

Third, I address adjustments proposed by Staff witness Mr. Kaufman and by Citizens' Utility Board of Oregon (CUB) witness Ms. Jaime McGovern related to minimum take requirements in the Company's coal contracts. I address the prudence of the contested contracts, while Company witness Mr. Brian S. Dickman addresses the modeling of these contracts in the 2017 TAM.

Q. Please summarize your reply testimony.

A. My testimony demonstrates that the Company's 2017 fuel strategy for the Jim Bridger plant is prudent and results in the least-cost, least-risk fuel supply. In (Commission) Order No. 13-387, the Commission approved a process under which the Company files a long-term fuel plan in the TAM to permit a multi-year, rather than annual, examination of the prudence of Jim Bridger fuel supply costs. The Long-Term Fuel Plan required by this order is similar to the long-term plans on which the Company has based its plant fueling strategies for many years. The Company filed its first Long-Term Fuel Supply Plan in compliance with Order No. 13-387 in December 2015.[1] Under this Plan, the Company will continue to rely primarily on coal from both BCC and the Black Butte mine—a fuel supply strategy the Commission approved as prudent in the 2014 TAM—while transitioning to greater reliance on coal from the Powder River Basin (PRB).

The Company's fuel supply costs in the 2017 TAM are fully consistent with the Company's Long-Term Fuel Plan. To respond to the dramatic market events over the last year, the Company is also preparing an updated Jim Bridger Fuel Supply Plan for filing in March 2017, to facilitate the multi-year review of BCC costs in the 2018 TAM.

Both Staff and ICNU challenge the Company's fuel costs in the 2017 TAM because they claim that PRB coal will be less expensive than BCC coal in 2017, so the Company should replace all BCC coal with PRB coal. But Staff's and ICNU's analysis concludes that PRB coal is lower cost than the current fuel plan only by ignoring the capital investment required to allow delivery of large volumes of PRB coal and the costs incurred to close the BCC mine, which would be incurred if BCC coal were no longer fueling the Jim Bridger plant. When both

[1] *In the Matter of PacifiCorp's 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 7 (Oct. 28, 2013).

these costs are accounted for, even using pricing from 2016, the basis for Staff's and ICNU's adjustments is eliminated.

In addition, Staff's and ICNU's adjustments lack any factual foundation because replacing BCC coal with PRB coal is a practical impossibility for 2017. Although the Jim Bridger plant can use small amounts of PRB coal, it will need new infrastructure, which will take several years to complete, to import the volume necessary to replace BCC coal. Thus, even if PRB coal were lower cost for 2017 than the Company's current fuel plan (which it is not), PRB coal is not a viable replacement for BCC.

To replace BCC coal with PRB coal in 2017, the Company would have had to make this decision at the latest in 2013. But Staff and ICNU rely on pricing from 2016, which applies an improper hindsight review. Neither Staff nor ICNU present any evidence that in late 2013, a reasonable utility would have made substantial capital investments in the Jim Bridger plant to allow delivery of PRB coal to replace BCC coal. Based on what was known in 2013, there was no expectation that PRB coal would be least cost in 2017. On the contrary, in 2013, the Company reasonably determined that the least-cost, least-risk fueling strategy relied on BCC and Black Butte coal, as confirmed by the Commission in the 2014 TAM order. Staff and ICNU have proposed an opportunistic adjustment based largely on recent market developments in the last year, including dramatic reductions in PRB coal costs and increasing BCC costs resulting from lower coal plant dispatch.

In response to Staff's and CUB's adjustments related to the Company's modeling of minimum take provisions in the Company's post-2015 coal contracts, I clarify that none of the handful of contracts adjusted for minimum take provisions in the Initial Filing or Reply Update were signed after 2015. I explain that the Company's coal supply agreements include minimum take requirements to obtain favorable pricing and that such provisions are standard in the industry. Finally, I demonstrate that the Company's coal stockpiles are used to cover normal fluctuations in coal markets and coal quality and are generally unavailable to mitigate the impact of minimum take requirements. As described by Mr. Dickman, this issue was significantly diminished by the updated coal plant dispatch in the Reply Update.

TAM UPDATE TO COAL COSTS

Q. Please describe the Company's coal costs update.

A. Under the TAM Guidelines, the Company updates coal costs to reflect actual and projected changes in coal and transportation contracts that increase and decrease costs.[2]

Q. What is the overall impact in this Reply Update?

A. Coal fuel expense for the 2017 TAM has increased $46.6 million on a total company basis, from $772.0 million in the Initial Filing to $818.6 million. This overall increase results from changes in both the modeled coal volumes and prices. The Reply Update increased coal volumes to 22.6 million tons compared

[2] Under the TAM Guidelines, the Company files the TAM in the spring, forecasting net power costs for the next year. This TAM was filed on April 1, 2016, using a 2017 test period, so the Company refers to it as the 2017 TAM. The Company also refers to previous TAMs by test period, not by the year of filing.

to 20.8 million tons in the Initial Filing. The higher coal volume increased coal fuel expense by $58.8 million total company partially offset by updated prices which reduced coal fuel expense by $12.2 million total company.

Q. What are the primary drivers of the $12.2 million total company coal fuel expense decrease due to lower coal prices in the Reply Update compared to the Initial Filing?

A. Third-party coal purchases and transportation unit cost decreases result in a [Begin Confidential] [redacted] [End Confidential] total company coal fuel expense reduction, primarily as a result of a new coal contract for the Dave Johnston plant, spot coal from PRB at the Jim Bridger plant and updated price indices. Affiliate mine unit cost decreases result in a [Begin Confidential] [redacted] [End Confidential] total company coal fuel expense reduction, primarily related to the additional incremental tons delivered from BCC to the Jim Bridger plant.

Q. Please identify the major components of the [Begin Confidential] [redacted] [End Confidential] **total company coal fuel expense reduction resulting from a decrease in prices from third-party coal and transportation contract supplies.**

A. The Company projects third-party coal and transportation supply cost decreases due to price changes at the coal-fired plants as set forth in Confidential Table 1 below. The decrease is primarily due to the April 2016 Request for Proposals (RFP) solicitation for the Dave Johnston plant, decreased coal prices for the Hunter and Huntington plants due to additional tier-2 contract price tons being delivered, spot coal from the PRB being delivered to the Jim Bridger plant, and reductions in the contract-specific producer and consumer price indices, which are a result of updated price and inflation escalation assumptions. These decreases are partially offset by an increase at the Naughton plant for the 2016 price reopener settlement and increases to the Company's forecast diesel fuel forward price curve. [Begin Confidential]

Confidential Figure 1: Coal and Transportation Contract Price Increase/(Decrease)

Plant	Contract	Millions ($)
Naughton	Kemmerer Mine Price	[redacted]
Wyodak	Wyodak Mine Contract Price	[redacted]
Cholla	Lee Ranch Coal and Rail Cost	[redacted]
Dave Johnston	BNSF Rail Rate	[redacted]
Dave Johnston	Powder River Basin Mines Prices	[redacted]
Hunter	Bowie Coal Cost	[redacted]
Huntington	Bowie and Castle Valley Coal Cost	[redacted]
Bridger	Black Butte Coal and Rail Cost	[redacted]
Bridger	PRB and Rail Cost	[redacted]
Colstrip	Rosebud Mine Cost	[redacted]
Hayden	Twentymile Mine Cost	[redacted]
Craig	Colowyo Mine Cost	[redacted]
Total Contract Costs Increase/(Decrease)		[redacted]

[End Confidential]

Q. Please describe the [redacted] total company coal fuel expense reduction related to the decrease in BCC unit costs due to incremental coal delivered by BCC.

A. In the Reply Update, the Company updated its Official Forward Price Curve, which increased wholesale natural gas and electricity prices. As discussed in Mr. Brian S. Dickman's reply testimony, this increase in wholesale natural gas and electricity prices increased coal dispatch in the Reply Update resulting in additional coal required at the Jim Bridger plant. As discussed in further detail below, BCC can produce an additional [Begin Confidential] [redacted] [End Confidential] tons of coal at an incremental price of [Begin Confidential] [redacted] [End Confidential] per ton. The additional incremental coal that BCC delivers to the Jim Bridger plant reduces the overall average unit cost of coal delivered from BCC to Jim Bridger and the associated coal fuel expense by [Begin Confidential] [redacted] [End Confidential]

JIM BRIDGER LONG-TERM FUEL STRATEGY

Q. What is the Company's fuel supply plan for the Jim Bridger plant in the 2017 TAM?

A. Similar to its historical fuel strategy, the Company will supply the Jim Bridger plant predominantly with coal from BCC and the Black Butte mine in 2017. In addition, in its Reply Update, a portion of the coal requirements at the Jim Bridger plant will be served by PRB coal. Based on the updated coal costs discussed above, and the economic dispatch produced by the GRID model, BCC will provide approximately 65 percent of the plant's requirement, with approximately 30 percent being provided by the Black Butte mine and the remaining 5 percent from the PRB.

Q. Please describe BCC.

A. BCC is a joint venture that mines coal at the Jim Bridger coal mine for delivery to the adjacent Jim Bridger plant. PacifiCorp (through its wholly-owned subsidiary Pacific Minerals, Inc.) owns a two-thirds interest in BCC, and Idaho Power Company (through its wholly-owned subsidiary Idaho Energy Resources Co.)

owns a one-third interest. PacifiCorp and Idaho Power Company have the same ownership percentages in the Jim Bridger plant. BCC began supplying coal to the Jim Bridger plant in 1974.

Q. Why has the Company historically relied on BCC for the majority of its fuel supply to the Jim Bridger plant?

A. The BCC mine is located adjacent to the Jim Bridger plant and the coal is delivered by conveyor, making BCC a reliable, competitively priced, and stable supply source for over forty years. The Jim Bridger plant was constructed to take advantage of the location of the BCC coal reserves. BCC was therefore designed as a mine-mouth coal source for the Jim Bridger plant and as such, the mine and the plant have been interrelated since they were built. The BCC mine was not intended to operate as an independent mine selling coal to the market; instead, its purpose was to provide a reliable, cost-effective fuel supply for the Jim Bridger plant. BCC's location adjacent to the Jim Bridger plant also provides significant price leverage on coal supplied from the nearby Black Butte mine. In addition, the location of the BCC mine reduces operational supply risk and price risk associated with rail transportation.

Q. Did the Commission recently review and approve the Company's reliance on the BCC and Black Butte mines in its fuel plan for the Jim Bridger plant?

A. Yes. In Order No. 13-387 in the 2014 TAM, docket UE 264, the Commission found that the Company's fuel supply for the Jim Bridger plant was "fair, just, and reasonable," as required by ORS 757.210.[3] The Commission concluded that,

[3] Order No. 13-387 at 6.

while BCC and Black Butte mine prices have fluctuated over the years, *over the long-term* they have both provided a reasonably priced, stable coal supply.[4]

Q. In that same case, did the Commission approve a process that contemplates review of the Company's fuel plan for the Jim Bridger plant on a multi-year basis?

A. Yes. The Commission directed PacifiCorp to file periodic long-term fuel plans for its affiliate mines to allow review of the Company's fuel strategy on a multi-year basis. In the 2015 TAM (docket UE 287), PacifiCorp filed a compliance proposal that described the purpose of the fuel plan, as well as the proposed content, mirroring the long-term fuel planning process the Company has used for many years.[5] No party to the 2015 TAM objected to or provided any comment regarding the proposal. The Company implemented its compliance proposal by filing the Jim Bridger Long-Term Fuel Plan in December 2015.

Q. Please describe the Company's Long-Term Fuel Supply Plan.

A. The Plan analyzed costs through 2037, the current depreciable life of the Jim Bridger plant in every jurisdiction except Oregon. The analysis compared the two most feasible coal supply options, including a base plan sourced from BCC, Black Butte, and PRB, with a transition to a higher reliance on PRB coal. The market alternative plan started with using BCC supplies but then transitioned to 100 percent PRB coal. The Company did not include other coal supply sources because of their limited ability to supply fuel and significant transportation costs. Ultimately, the analysis found that the least-cost, least-risk option is to transition

[4] *Id.*
[5] Docket UE 287, PAC/201, attached as Exhibit PAC/501.

to greater (but not exclusive) reliance on PRB coal, [Begin Confidential] [redacted] [End Confidential]

Q. According to the Long-Term Fuel Supply Plan, what is the timeframe and cost for transitioning to greater reliance on PRB coal?

A. The Long-Term Fuel Supply Plan identifies PRB coal as a preferred market alternative beginning in [Begin Confidential] [redacted] [End Confidential] to allow sufficient time to install the infrastructure needed at the plant to allow for PRB deliveries. As described in the Plan, to replace large volumes of BCC coal with PRB coal, the Company will need to install the necessary rail and handling facilities to accept significant deliveries of PRB coal and modify the Jim Bridger plant to allow it to burn PRB coal reliably, efficiently, and in conformance with the plant's permitting.[6] The infrastructure improvements necessary to receive and burn PRB coal will cost the Company approximately [Begin Confidential] [redacted] [End Confidential] and take up to six years to complete.[7]

Q. Is the fuel supply plan in the 2017 TAM consistent with the Jim Bridger Long-Term Fuel Supply Plan?

A. Yes. The fuel supply plan for Jim Bridger in the 2017 TAM is consistent with the Jim Bridger Long-Term Fuel Supply Plan, recognizing that only a limited portion of the plant's coal requirements could be met with PRB coal in 2017. As described below, the Company plans to begin transitioning to a new fuel strategy in [Begin Confidential] [redacted] [End Confidential] to respond to recent changes in the power markets. Over the long-term, the Company's strategy

[6] Staff/215, Kaufman/8-9.
[7] Staff/215, Kaufman/9.

[Begin Confidential] [redacted] [End Confidential]

Q. In light of changing market conditions, is the Company developing a new Long-Term Fuel Plan for filing in the spring of 2017?

A. Yes. In its compliance proposal in docket UE 287, the 2015 TAM, the Company committed to updating its Long-Term Fuel Plan every five years or as necessary to address major milestones in coal supply cycles.[8] Given the rapid changes in coal and energy market conditions, PacifiCorp will prepare a new Long-Term Fuel Plan to file concurrently with its 2017 Integrated Resource Plan in March 2017. The Company will reflect changes in the Long-Term Jim Bridger Fuel Plan in the 2018 TAM, which will also be filed at that time. Among other options, the Company is evaluating options to accelerate the transition to larger volumes of PRB coal to accomplish the change in third-party fuel supply earlier than [Begin Confidential] [redacted] [End Confidential] and the impact of reduced consumption.

Q. Are the parties' adjustments to BCC costs in this case fundamentally at odds with the long-term review of Jim Bridger fuel supply strategy adopted by the Commission?

A. Yes. Staff's and ICNU's adjustments both focus exclusively on BCC costs in the 2017 test period without consideration of the prudence of the Company's historical or current long-term fuel plans.

[8] PAC/501 at 2.

Q. Does Staff contest the reasonableness of the Long-Term Fuel Plan in this case?

A. Yes. Even though Staff did not respond to the Company's compliance proposal or the Plan at the time of filing, Staff now claims that the Long-Term Fuel Supply Plan does not adequately evaluate market options or provide sufficient data for parties to evaluate the prudence of the Company's BCC operations.[9] Specifically, Staff claims that the Plan unreasonably examines only one market alternative to BCC—PRB coal—and only examines one point in time to transition to market—[Begin Confidential] [redacted].[10] [End Confidential]

Q. Why didn't the Plan analyze the potential of switching to market alternatives earlier than [Begin Confidential] [redacted]**?** [End Confidential]

A. As explained above, the infrastructure improvements necessary to receive and burn large volumes of PRB coal are estimated to take up to six years to permit and construct. Using a six-year timeframe, the transition to PRB or other alternatives could occur in approximately [Begin Confidential] [redacted]. [End Confidential] Given that the current economic coal reserves at the BCC underground mine would be exhausted in [Begin Confidential] [redacted] [End Confidential] according to the existing long-term mine plan, the Long-Term Fuel Plan chose the transition to market coal in [Begin Confidential] [redacted] [End Confidential] as the best option.

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[9] Staff/200, Kaufman/60.
[10] Staff/200, Kaufman/61.

Q. Staff also claims that the Plan does not accurately estimate PRB costs, including transportation.[11] Do you agree?

A. No. Staff claims that the "average cost of transporting PRB coal to market in 2010 was $17.50 per ton. After escalating for rail transportation cost index this is the equivalent of $19.15 per ton in 2015 dollars." Staff claims that because the Company's long-term fuel plan utilized a forecast price of [Begin Confidential] $[redacted] [End Confidential] per ton for 2015, the Company has inflated PRB transportation costs by [Begin Confidential] [redacted] percent. [End Confidential] The Company had a contract in place with Union Pacific Railroad (UP) to transport small volumes of PRB coal to the Jim Bridger plant in 2015. The price under this contract was actually [Begin Confidential] $[redacted] [End Confidential] per ton inclusive of utilizing UP railcars.

Q. Staff also faults the Company for not analyzing the possibility of replacing BCC with coal from the Uinta Basin.[12] Is that a reasonable market alternative?

A. No. The delivered price of Uinta Basin coal to the Jim Bridger plant would be cost prohibitive. Relying on the fall 2015 Energy Ventures Analysis, Inc. (EVA) Long-Term Outlook Coalcast, the Company estimated that the coal cost alone for Uinta Basin coal from Utah would be [Begin Confidential] $[redacted] [End Confidential] per ton for 11,800 Btu/lb coal in 2017. After adjusting the heat content of Uinta Basin 11,800 Btu/lb coal to PRB 8,800 Btu/lb coal, this price

[11] Staff/200, Kaufman/61-62.

[12] Staff/200, Kaufman/63.

would be equivalent to [Begin Confidential] [redacted] [End Confidential] per ton. To compete with the PRB delivered price of approximately [Begin Confidential] [redacted] [End Confidential] per ton during 2017 (see Confidential Table 4 below), the transportation price would have to be in the range of [Begin Confidential] [redacted] [End Confidential] per ton. The Company does not have definitive pricing for rail or trucking transportation cost from Utah or Colorado to the Jim Bridger plant. The Company estimates, however, the transportation price for that distance of over 370 miles would far exceed the [Begin Confidential] [redacted] [End Confidential] per ton range. Additionally, the quantity of coal needed to replace BCC coal entirely with Uinta Basin coal would require the same additional expanded rail unloading facilities as if the market alternative coal were PRB coal.

STAFF'S COAL PRICE ADJUSTMENT

Q. Please describe Staff's proposed adjustment related to BCC coal costs.

A. Staff contends that PRB coal is an available, lower-cost alternative to BCC coal and that the Company was imprudent for relying on BCC coal for 2017 instead of PRB coal.[13] Staff recommends a disallowance based on the alleged price difference between BCC and PRB coal. Staff's adjustment decreases NPC by $40.9 million (total system) or $10.4 million on an Oregon-allocated basis.[14]

Q. Is Staff's adjustment reasonable?

A. No. As noted above, according to the Long-Term Fuel Supply Plan submitted in December 2015, the Company plans to transition to PRB coal for the majority of the fuel supply for the Jim Bridger plant in [Begin Confidential] [redacted]. [End

[13] Staff/200, Kaufman/66-67.
[14] Staff/200, Kaufman/67.

Confidential] However, implementation of the plan will require major capital investments over several years. For PRB coal to entirely replace BCC coal in 2017, as Staff now contends is prudent, the Company would have had to change its fuel plan during 2013 at the latest, to begin an expedited conversion process to PRB coal in 2014. There was no basis at that time, however, to conclude that PRB coal would be lower cost than BCC coal in 2017, after accounting for all costs.

Staff fails to acknowledge that it will take several years to complete the permitting and construction of the facilities and plant modifications required to entirely replace BCC coal with PRB coal at the Jim Bridger plant. Staff also fails to fully account for the necessary capital infrastructure costs, unrecovered mine investments, final reclamation obligation or mine closure.

Q. What is the basis for Staff's claim that PRB is an available market alternative for the Jim Bridger plant's coal supply?

A. Staff claims that PRB coal is identified as a viable coal source in the Company's Long-Term Fuel Supply Plan.[15] But the Long-Term Fuel Supply Plan identifies PRB coal as a viable market alternative beginning in [Begin Confidential] [redacted], [End Confidential] not 2017, and recognizes the infrastructure needed at the plant to allow for a higher volume of PRB deliveries.

The Jim Bridger plant is not currently equipped to receive significant quantities of rail deliveries to entirely replace BCC coal, which is delivered to the plant via a conveyor belt from the mine. There are also differences in the coal

[15] Staff/200, Kaufman/51.

quality that require other modifications to the Jim Bridger plant to meet the permitting and safety requirements in order to burn significant volumes of coal from the PRB.

As described in the Plan, PacifiCorp's share of the capital expenditures required for PRB coal to replace BCC coal is [Begin Confidential] $[redacted] [End Confidential] covering the installation of rail and handling facilities to accept delivery of PRB coal and modifications of the plant to burn PRB coal.[16] In 2016 dollars, Staff calculates that this investment exceeds [Begin Confidential] $[redacted][17] [End Confidential] Staff's portrayal of the [Begin Confidential] $[redacted] [End Confidential] is overstated because PacifiCorp owns two-thirds of BCC. The [Begin Confidential] $[redacted] [End Confidential] is correctly stated as [Begin Confidential] $[redacted] [End Confidential] in un-escalated dollars and as [Begin Confidential] $[redacted] [End Confidential] after including AFUDC, capital surcharges and price escalation.

Moreover, the infrastructure improvements necessary to receive and burn significant quantities of PRB coal will take years to complete. The Plan calls for permitting and construction to begin in [Begin Confidential] [redacted] [End Confidential] to allow for PRB deliveries and efficient plant operation in [Begin Confidential] [redacted], [End Confidential] a six-year transition window.[18] While PacifiCorp could potentially expedite this transition and reduce it to approximately four years, this is the minimum time required. The timeframe of

[16] Staff/215, Kaufman/9.
[17] Staff/200, Kaufman/55.
[18] Staff/215, Kaufman/9.

the permitting process is not entirely under the Company's control however, as the various external agencies that issue those permits may require additional time to complete their processes. Thus, PRB coal is not a viable market alternative to BCC coal in 2017 because the Company could not physically receive enough volumes to entirely replace BCC coal.

Q. Staff also cites the Company's testimony from the 2014 TAM, docket UE 264, indicating that it had recently purchased PRB coal.[19] Is this testimony relevant here?

A. No. The testimony Staff cites does not relate to the Jim Bridger plant. The 2014 TAM testimony related to the Dave Johnston plant, which has traditionally relied on PRB coal for the majority of its fuel needs since the Company's Dave Johnston Mine in Glenrock, Wyoming was closed. My direct testimony contains a similar discussion of PRB coal at the Dave Johnston plant.[20] The fact that the Company purchases PRB coal to fuel other plants does not necessarily mean that a significant amount of PRB coal is a viable alternative to replace BCC coal for the Jim Bridger plant at this time.

Q. What is the basis for Staff's claim that PRB coal is less expensive than BCC coal?

A. Staff claims that as of May 2016, BCC coal costs are 179 percent higher than PRB coal.[21] Staff further claims that for 2017, PRB coal will be substantially cheaper than BCC coal, even after accounting for transportation, but fails to

[19] Staff/200, Kaufman/53.
[20] PAC/200, Ralston/7.
[21] Staff/200, Kaufman/52.

account for dust suppression and handling costs,[22] and the capital investments necessary to deliver and burn significant volumes of PRB coal.[23] Additionally, Staff does not include costs associated with unrecovered mine investments, final reclamation obligation or mine closure. In the calculation of the most recent BCC monthly cost, Staff fails to account for the fact that production at the mine has been reduced during 2016 due to various factors including reduced generation demand at Jim Bridger plant. It is likewise inappropriate to use a short-term view–especially a one-month snapshot–of costs in 2016 and make comparisons or decisions related to long-term fuel plans.

Q. Does Staff's analysis take into consideration the time required to construct the facilities necessary to receive large volumes of PRB coal?

A. No. Staff's calculation of PRB costs for 2017 is based on information presented in the workpapers for my direct testimony, but omits the relevant costs discussed above. Thus, implicit in Staff's adjustment is the incorrect assumption that the Company could have constructed the necessary facilities to handle large volumes of PRB coal this year, to allow receipt of PRB coal in 2017.

Q. Based on what the Company knew or should have known in 2013, would it have been prudent to make the decision to replace BCC coal with PRB coal in 2017?

A. No. The Company's 2013 forecasts, both long- and short-term, did not indicate that PRB coal would be least-cost by 2017. Instead, the Company's market evidence from 2013 confirms that PRB coal was expected to be a higher-cost

[22] Staff/200, Kaufman/52.
[23] Staff/200, Kaufman/54-55.

source of coal in 2017, due to the cost of rail transportation and the capital expenditures required to receive and burn large quantities of PRB coal, which are discussed above.

In fact, based on data available to the Company in the fall of 2013, including the amortization of a regulatory asset and capital expenditures, the Company estimates that the total delivered costs for PRB coal would be [Begin Confidential] $[redacted][End Confidential] per ton in 2017. At that same time, fuel costs to the Jim Bridger plant were forecast at [Begin Confidential] [redacted] [End Confidential] per ton. See Confidential Figure 2 below.

[Begin Confidential]

Confidential Figure 2
Bridger Plant Market Comparison
Hypothetical 2017 Test Year using information available to the Company in 2013
Fuel Costs

[redacted]

(a) PRB price per Fall 2013 EVA Coalcast
(b) PRB rail price per the Company's internal calculations
(c) Capital investment cost based on levelized revenue requirement through 2029 consistent with Oregon stipulations (excludes AFUDC and capital surcharge)
(d) PacifiCorp regulatory asset amortization assumes four years based on levelized revenue requirement of mine closure, reclamation obligation and unrecovered investment in BCC mine

[End Confidential]

Q. **After 2013, did forecast market data continue to confirm that a fuel plan using BCC coal remained least-cost for the Jim Bridger plant?**

A. Yes. In the Company’s Wyoming general rate case filed in fall 2015, the Company conducted an additional analysis of PRB coal prices that demonstrated that reliance on BCC coal remained the least-cost fueling option in 2016. That analysis demonstrated that the total Jim Bridger plant delivered coal cost including the return on rate base at BCC was approximately [Begin Confidential] $[redacted] [End Confidential] per ton for 2016. In contrast, based on the 2015 EVA Long-Term Outlook Coalcast, the Company estimated that the total delivered costs for PRB coal would be [Begin Confidential] [redacted] [End Confidential] in 2016.[24] In addition, relying on an April 2015 RFP for PRB coal to be delivered to the Company's Dave Johnston plant in 2016, the Company determined that the total delivered costs for PRB coal would be [Begin Confidential] [redacted] [End Confidential] in 2016. Thus, based on what the Company prepared in fall 2015, a fuel plan using BCC coal remained the preferred option for 2016.

Q. Have PRB coal prices demonstrated significant volatility in recent years?

A. Yes. To illustrate the volatility in coal market price projections, EVA's 2014 Coalcast projected PRB coal pricing in calendar year 2017 to be [Begin Confidential] $[redacted] [End Confidential] per ton for coal containing 8,800 Btu/lb. EVA's 2015 Coalcast projected coal pricing in calendar year 2017 to be [Begin Confidential] [redacted] [End Confidential] per ton for coal containing 8,800 Btu/lb. See Confidential Figure 3 below.

[Begin Confidential]

[24] Because BCC and PRB coal have different heat contents, for a fair comparison these prices were adjusted so that the dollar-per-ton figure for each option includes the same heat content.

Confidential Figure 3

[End Confidential]

This is a projected reduction in 2017 PRB coal costs of 33 percent. This drastic change is predominantly driven by lower natural gas prices resulting in displacing coal-fueled generation with natural gas fueled generation, uncertainties associated with recent governmental environmental policies, and the increased availability of renewable energy sources displacing fossil fueled-generation. As shown in Confidential Figure 3 above, EVA has recently forecast the 2017 PRB 8,800 Btu/lb price to be [Begin Confidential] [redacted] [End Confidential] per ton. Pursuant to the April 2016 RFP for PRB coal to be delivered to the Company's Dave Johnston plant, the Company recently obtained a bid for 8,800 Btu/lb adjusted coal as low as [Begin Confidential] $[redacted] [End Confidential] per ton in 2017. However, the risk exists that the actual pricing available for any coal in 2017 for deliveries to Jim Bridger could be higher depending upon the market conditions which have been volatile in the past few years.

Q. How does recent price volatility inform the Company's fuel strategy?

A. The volatility in prices demonstrates that fuel plans, by design, require a long-term perspective and cannot and should not be abandoned by short-term market anomalies or cyclical changes, such as those raised by Staff and ICNU in this case. The Company is actively modifying its coal procurement strategy to respond to current, unprecedented changes in the energy markets. As described above, however, the Company cannot simply switch reliance from BCC coal to PRB coal on a year-to-year basis. The market changes that have occurred in the last year were clearly not forecast in the 2013-2015 timeframe.

Q. Staff claims that the Company historically has not considered PRB coal as an alternative to BCC coal, citing the Company's testimony in the 2014 TAM, docket UE 264.[25] How do you respond?

A. In the 2014 TAM, docket UE 264, the Company's testimony focused on Black Butte coal because the Company was responding to claims by ICNU that Black Butte was lower cost than BCC. The Company never compared PRB coal to BCC coal in docket UE 264 because there was no dispute that BCC was more cost effective than PRB. As described in more detail in Mr. Dalley's testimony, the Company provided testimony in the 2010, 2011, and 2012 TAMs that PRB coal was not a viable alternative to BCC coal due to the cost of transportation and infrastructure upgrades required to receive large volumes of PRB coal. That remained true in the 2013 and 2014 TAMs, even though the point was not at issue in those cases.

Q. Staff further claims that PRB coal will be less than BCC coal in every year until 2036.[26] Do you agree with Staff's analysis?

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[25] Staff/200, Kaufman/59.
[26] Staff/200, Kaufman/57.

A. No. In Figure 4 below, the Company shows the incompleteness of Staff's analysis for 2017. The point is also irrelevant to the prudence issue in this case because Staff's PRB prices are based on a June 2016 forecast.[27] The Company could not have closed BCC and replaced the BCC coal volumes with PRB coal in 2017 in six months.

Q. If the Company were to entirely replace BCC coal with PRB coal, are there any other costs that Staff has not included in its analysis?

A. Yes. Staff's analysis assumes that if the BCC mine were closed, customers are not responsible for future closure costs, final reclamation, and undepreciated assets.[28] Mr. Dalley's testimony explains why this assumption is incorrect. An accurate comparison of BCC and PRB coal must include the full costs of BCC mine closure.

Q. What types of costs would be incurred if the BCC mine were closed?

A. Similar to the closure of the Deer Creek mine approved by the Commission in Order No. 15-161, early closure of BCC mining operations would create asset impairment issues, accelerate funding requirements for final reclamation obligations and trigger unplanned expenditures for mine closure, severance and royalty costs. These costs would result in the creation of a regulatory asset, which would be amortized over future periods. The closure of the Company's Trail Mountain mine and Dave Johnston mine resulted in the creation of similar regulatory assets.

[27] Staff/244.
[28] Staff/200, Kaufman/56, 63-64.

Q. Have you developed a comparison of PRB coal costs and the current fuel plan for Jim Bridger that includes the actual costs involved in changing fuel supplies?

A. Yes. Assuming that it were possible to fuel the plant with significant amounts of PRB in 2017 (which the Company has demonstrated is unrealistic), a cost comparison factoring in the additional costs of amortization of the regulatory asset and capital investment demonstrates that the Company's fuel plan for the Jim Bridger plant in the 2017 TAM remains the most cost effective option for customers. This is shown below in Confidential Figure 4. Based on data available to the Company in 2016, including the amortization of a regulatory asset and capital expenditures, the Company estimates that the total delivered costs for PRB coal would be [Begin Confidential] $[redacted][End Confidential] per ton in 2017. At that same time, fuel costs to the Jim Bridger plant are forecast at [Begin Confidential] [redacted] [End Confidential] per ton in the Reply Update.

[Begin Confidential]

Confidential Figure 4
Bridger Plant Market Comparison
2017 Test Year using information available to the Company in 2016
Fuel Costs

[redacted]

[redacted]

[End Confidential]

Q. Staff also contends that replacing BCC coal with PRB coal would not necessarily result in the closure of the BCC mine because it could sell into the general coal market.[29] Is this a reasonable assumption?

A. No, Staff's claim is entirely unsupported. There are two fundamental flaws in Staff's assumption that BCC could sell its coal on the open market. First, the mine has no loadout facilities to move BCC coal from the mine to another location. Thus, significant capital investments would be required for the construction of a loadout facility and attainment of any necessary permits.

[29] Staff/200, Kaufman/67.

Second, even if the mine had the necessary infrastructure to move its coal, there is no current market for BCC coal. Southwest Wyoming is a niche market with limited participants. The relatively low heat content in comparison to Colorado and Utah coals and the high ash content relative to PRB coal confines Southwest Wyoming coal largely to the local area. Thus, it is clear that the BCC mine will close if it no longer serves the Jim Bridger plant.

Q. How do you respond to Staff's claim that the Company "may not be operating [BCC] in customers' interests?"[30]

A. I strongly disagree with this claim. Staff argues that the Company does not perform due diligence analysis related to capital investments at the mine.[31] On the contrary, the Company conducts thorough and comprehensive due diligence analysis before making any capital investments in BCC and regularly evaluates least-cost, risk-adjusted fuel forecasts for the Jim Bridger plant. BCC is subject to the PacifiCorp asset capitalization policy and also maintains distinct capital policy and procedures. As described in the "Capital Policy and Procedures" for BCC provided in in response to Staff Data Request 93, a capital approval document is required for each project over a certain value. An accompanying financial analysis is performed for each project. Higher value projects require additional justification and scrutiny. Moreover, because the mine is consolidated with PacifiCorp for ratemaking purposes, any capital investment in the mine is subject to the same prudence review as all other Company investments.

[30] Staff/200, Kaufman/32.
[31] Staff/200, Kaufman/31-32.

Q. Have any of the Company's capital investments in BCC been found imprudent by the Commission?

A. No.

Q. Are all of the anticipated capital investments included in the Company's Long-Term Fuel Supply plan?

A. Yes. Thus, the full revenue requirement impact of continued operation of BCC is fairly compared to the revenue requirement impact of transitioning to market alternatives.

Q. Staff also testifies that the Company has dramatically increased its capital investments in BCC since the acquisition of PacifiCorp by Berkshire Hathaway Energy in 2005.[32] How do you respond?

A. The construction of the BCC underground mine began in 2004 with the construction of the mine portal and subsequent purchase of significant capital mining equipment over the course of several years. The construction of the underground mine included PacifiCorp's share of approximately [Begin Confidential] $[redacted] [End Confidential] in capital assets, reflected in Oregon rates in docket UE 170.[33] A significant amount of underground mine equipment was purchased and placed in service in 2007 as longwall mining production began in that year. These capital investments at the mine correspond to the development of the underground mine and are unrelated to the change in ownership of PacifiCorp.

[32] Staff/200, Kaufman/32-34.
[33] See *Pacific Power & Light Co. Request for General Rate Increase*, Docket No. UE 170, Order No. 05-1050 at 6 (Sept. 28, 2005); Docket No. UE 207, PPL/202, Lasich/3-4.

Q. Staff testifies that the Company's forecasts of 2017 BCC production and prices have changed in recent years, with the price increasing and the production decreasing.[34] How do you respond?

A. As Staff's testimony confirms, BCC prices and production have been volatile in recent years, reflecting broader market volatility. This underlines the importance of examining fuel supply plans on a long-term basis. Staff's testimony also confirms that, at the critical time the Company would have needed to decide to close BCC and replace its output with PRB coal in 2017, BCC's costs were expected to be lower.

Q. Please respond to Staff's criticism of the Company's 2016 business plan.[35]

A. Energy market conditions changed drastically from when the plan was developed in the summer of 2015 to early 2016. The 2016 business plan and BCC mine plan developed in 2015 pre-dated many of these changes. The Company developed a BCC mine plan with lower production levels for the 2017 TAM based upon market conditions and the Company's experience in spring 2016 with reduced generation levels at the Jim Bridger plant. For business planning purposes, the Company continues to evaluate the BCC mine plan and operations and will make additional changes as needed in response to market conditions.

The BCC mine plan utilized for the 2017 TAM anticipated delivered volumes of [Begin Confidential] [redacted] [End Confidential] tons (PacifiCorp share). However, if market conditions dictate, the mine could produce an incremental amount of approximately [Begin Confidential] [redacted] [End

[34] Staff/200, Kaufman/31.
[35] Staff/200, Kaufman/37, 45.

Confidential] tons above the existing mine plan. Flexing the mine up to produce this incremental volume would require additional production shifts, with the cost for this limited quantity equal to the incremental price of production of [Begin Confidential] [redacted] [End Confidential] per MMBtu. The Company has reflected the ability of BCC to deliver this incremental quantity of coal in its Reply Update. Further ramping the mine to deliver quantities above the total [Begin Confidential] [redacted] [End Confidential] tons would be a long-term commitment requiring additional staffing.

Q. Staff further contends that reliance on PRB coal would result in optimal dispatch of the Jim Bridger plant, which would create additional cost savings not accounted for in Staff's analysis.[36] Please comment.

A. Staff's analysis is focused on fuel supply for and dispatch of the Jim Bridger plant in 2017. As I have described in my testimony, the Company does not have the ability to receive and burn significant quantities of PRB coal at the Jim Bridger plant in 2017. In the Reply Update, however, the Company has recognized the potential to receive deliveries of up to [Begin Confidential] [redacted] [End Confidential] tons of PRB coal during 2017 for consumption at the Jim Bridger plant at an incremental cost of [Begin Confidential] $[redacted] [End Confidential] per MMBtu.

[36] Staff/200, Kaufman/56.

ICNU'S LOWER OF COST OR MARKET ADJUSTMENT

Q. What does the lower of cost or market rule require?

A. The lower of cost or market rule states that transactions between utilities and affiliates "shall be recorded in the energy utility's accounts at the affiliate's cost or the market rate, whichever is lower."[37] The rule defines "market rate" as "the lowest price that is available from nonaffiliated suppliers for comparable services or supplies."[38] As discussed in Mr. Dalley's testimony, the Commission has not historically applied this standard to BCC coal.

Q. What is the basis for ICNU's recommendation that the Commission apply the lower of cost or market pricing to coal acquired from BCC?

A. ICNU claims that BCC is no longer a reasonably priced option for the Company because the market price for coal in Wyoming has been declining, while BCC costs have been increasing.[39] ICNU's high-level analysis, which looks broadly at state-wide coal costs, fails to account for coal costs at the Jim Bridger plant. The evidence in recent TAM filings contradicts ICNU's assertion and demonstrates that coal costs for both BCC and Black Butte have been increasing at a comparable rate and that in the 2014, 2015, and 2016 TAMs, the costs of coal have been comparable.

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[37] OAR 860-027-0048(4)(e).
[38] OAR 860-027-0048(1)(i).
[39] ICNU/100, Mullins/8-9.

Q. What market alternative does ICNU claim should replace BCC coal?

A. Like Staff, ICNU claims that PRB coal is least-cost and that the Company should use PRB coal instead of BCC coal in 2017.[40]

Q. Are there any problems with ICNU's analysis?

A. Yes. First, like Staff, ICNU ignores the infrastructure requirements necessary to receive and burn significant quantities of PRB coal. ICNU simply assumes the Company can replace BCC with PRB coal without any delay to construct the necessary facilities. Thus, like ICNU's lower of cost or market recommendation in docket UE 264, the market alternative here is also unrealistic and cannot actually replace BCC coal in 2017.

Second, ICNU's analysis does not include fuel surcharge, dust suppression, coal handling, unrecovered mine investments, final reclamation obligation and mine closure costs.

Third, ICNU's analysis amortizes the capital investment over a 20-year period which extends beyond the timelines in Senate Bill 1547 which phases out coal-fired generation in Oregon by 2030.

MINIMUM TAKE PROVISIONS IN COAL CONTRACTS

Q. Have Staff and CUB challenged costs in the 2017 TAM related to the minimum take provisions in certain of the Company's coal contracts?

A. Yes. Staff contests how the Company modeled minimum take provisions in the 2017 TAM and, in testimony, also claims that contracts containing these provisions "may" be imprudent.[41] Staff clarified during discovery, however, that

[40] ICNU/100, Mullins/12, 15.
[41] Staff/200, Kaufman/22, 24.

it is not challenging the prudence of the post-2015 contracts and therefore Staff's adjustment is limited to the modeling of the minimum take provisions in GRID.[42]

CUB directly challenges the prudence of minimum take provisions in the Company's coal contracts executed since 2015 and recommends that all "costs and impacts" of these contracts be disallowed.[43] Company witness Mr. Dickman addresses the modeling of these contract provisions, while I address their prudence.

Q. Which coal supply contracts has the Company executed since 2015?

A. The coal supply contracts executed since 2015 relate to the Huntington, Jim Bridger, and Dave Johnston plants. Although Staff claims that the Company entered into four contracts since 2015,[44] the contract related to the Naughton plant that indicates a term beginning in 2017 was actually executed in 2010, but included two distinct terms.[45]

Q. Were any of the post-2015 coal supply contracts subject to a minimum take adjustment in this case?

A. No. As described by Mr. Dickman in the Company's Initial Filing, there were four plants adjusted to account for minimum take requirements: [Begin Confidential] [redacted] [End Confidential] In the Reply Update, only [Begin Confidential] [redacted] [End Confidential] are subject to a minimum take adjustment. Therefore, none of the minimum take

[42] PAC/502 (Staff Response to PacifiCorp Data Request 11).
[43] CUB/100, McGovern/9.
[44] Staff/200, Kaufman/24.
[45] Staff/209.

provisions in the contracts challenged by CUB are actually at issue at this point in the case.

Q. Are all three contracts executed since 2015 long term coal supply contracts?

A. No. The coal supply contract for the Huntington plant is the only long-term coal supply agreement executed since 2015. The Jim Bridger contract expires in 2017 and the Dave Johnston contract expires in 2018.

Q. Please explain how minimum take provisions operate in the Company's coal contracts.

A. A minimum take, or "take-or-pay," provision generally requires the Company to purchase a minimum specified amount of coal over a given time period.

Q. Are minimum take provisions a standard aspect of coal supply contracts?

A. Yes. Minimum take provisions are an essential component of virtually all long-term coal supply agreements and constitute the consideration required to obtain favorable pricing. Coal producers cannot continue to invest in extending the operations at the existing mines without coal sales contracts and some guarantee that they will be able to sell a minimum volume.

Q. Please explain why it was prudent for the Company to continue to execute coal supply contracts with minimum take provisions in 2015 and beyond.

A. Coal supply contracts, which necessarily include minimum take provisions, ensure that a reliable supply of coal will be committed and available to fuel the Company's plants at predictable and stable prices, terms, and conditions. Absent a coal supply agreement, the Company would be required to supply its plants exclusively with spot market purchases. Relying exclusively on the spot market, however, is an extremely risky strategy that would expose customers to substantial and unreasonable price and supply risk. The Company has never relied exclusively on the spot market and doing so in these uncertain times would be categorically imprudent.

Q. Has CUB provided any contract-specific evidence that the Company acted unreasonably in executing coal contracts with minimum take provisions since 2015?

A. No. CUB fails to present any actual evidence related to specific contracts. CUB simply argues that "an expensive and binding commitment to coal in the current environmental, federal, and regulatory atmosphere is imprudent."[46] But CUB provides no analysis or evidence indicating that any of the contracts it references were imprudent when they were executed or that a reasonable utility would rely exclusively on the spot market, rather than a coal supply contract. Moreover, CUB does not acknowledge that the minimum take provisions in the challenged contracts are not even an issue this case because the Company's modeling exceeded the minimum take under those contracts.

Q. Is CUB's argument in this case consistent with its past positions?

A. No. As noted above, the Company's only post-2015, long-term coal supply agreements is with Bowie Coal Sales LLC for delivery at the Huntington plant. This contract replaced the coal that was previously provided by the Company's affiliate-owned Deer Creek mine, which closed in 2014. In docket UM 1712, CUB entered into a stipulation with the Company that included a term specifically

[46] CUB/100, McGovern/7.

stating that this coal supply contract was prudent.[47] Moreover, this contract has significant provisions in the contract to account for changes in law or regulation.

Q. Staff also suggests that the Company should be relying on its ability to stockpile coal at its plants to mitigate the impact of minimum take provisions.[48] Is this a reasonable suggestion?

A. No. The majority of the Company's coal plant stockpiles have limited capacity levels. As such, surging stockpile levels up or down would not provide adequate flexibility on a repeated year-over-year basis to mitigate the impact of minimum take provisions. The Company uses the stockpiles to adjust for actual conditions when they differ from the forecast due to changes in market or coal quality conditions. Losing this operational flexibility would subject customers to added supply risk and create situations where the Company is forced to operate in a sub-optimal condition.

Q. CUB also claims that the Company can re-sell the coal it is required to purchase, to mitigate the impact on customers.[49] Is this feasible?

A. No. From a physical and practical position, the existing facilities at most plants do not have the infrastructure to load coal for sale. Environmental permitting and significant amounts of capital infrastructure would be required to allow loading out of coal. The sale price after purchasing this coal, adding the handling costs, and adding transportation costs would make the coal unmarketable. As stated above, the Company manages any differences between coal purchases and coal

[47] Docket UM 1712, Stipulation ¶ 9 (Mar. 25, 2015).
[48] Staff/200, Kaufman/24.
[49] CUB/100, McGovern/8.

consumption by maintaining inventory stockpiles as well as adjusting the annual nominations of coal that are required in the prior year.

Q. CUB is also concerned that the Company is operating its coal plants in a way that will cause long-term damage and greater forced outages.[50] Is this a valid concern?

A. No. CUB is using information from a study that does not represent how the Company forecasts that its plants will operate. The study references a plant that has cycled on and off as many as four times a day. The Company's forecast is that while capacity factors on the plants will drop, they will still be significantly high capacity factors and will be online and operating the majority of the time. While the Company will be monitoring the condition of the plants and the operating profile, it does not expect significant impacts to availability or costs for the remaining life of the units.

Q. Does this conclude your reply testimony?

A. Yes.

[50] CUB/100, McGovern/8.

Docket No. UE 307
Exhibit PAC/501
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Dana M. Ralston

PacifiCorp Compliance Proposal for Periodic Long-Term Fuel Plans

August 2016

PACIFICORP COMPLIANCE PROPOSAL—ORDER NO. 13-387 PERIODIC FUEL SUPPLY PLANS FOR PACIFICORP'S AFFILIATE MINES

A. Background

PacifiCorp is a co-owner of the Jim Bridger plant in Wyoming. The Jim Bridger plant obtains coal supply from the Bridger Coal Company (BCC), which is co-owned by PacifiCorp.[1] PacifiCorp owns the Huntington and Hunter plants in Utah. These plants obtain coal supply from the Deer Creek Mine, owned by Energy West Mining Company (EWMC). EWMC is a wholly owned subsidiary of PacifiCorp. Collectively, BCC and EWMC are referred to as "captive coal" mines. For regulatory purposes, PacifiCorp's captive coal mines are consolidated for reporting and ratemaking on PacifiCorp's books.[2] The Commission has approved the coal supply agreements between PacifiCorp and BCC and PacifiCorp and EWMC under the Commission's transfer pricing rule, OAR 860-027-0048.[3] The Commission conditioned this approval upon the right to review the coal supply agreements for reasonableness in subsequent rate proceedings and the requirement that the Company notify the Commission of any substantive changes to the coal supply agreements, including material changes in cost.

In Order No. 13-387 in PacifiCorp's 2014 Transition Adjustment Mechanism (TAM), the Commission resolved a challenge to Jim Bridger's fuel supply costs by adopting a proposal to facilitate implementing prudence and affiliated interest standards for PacifiCorp's captive mines in future rate cases.[4] The proposal, which was endorsed by PacifiCorp, Staff, and CUB, contemplates PacifiCorp's preparation of periodic fuel supply plans that compare affiliate fuel supply to alternative fuel supply options, including market alternatives. PacifiCorp has prepared this compliance proposal in response to Order No. 13-387.

B. Long-Term Fuel Supply Plans

1. **Purpose of Long-Term Fuel Supply Plans**. The purpose of the long-term fuel supply plan for plants fueled by coal from captive coal mines is to demonstrate that the fuel supplies are "fair, just, and reasonable,"[5] and satisfy the Commission's prudence and affiliate interest standards. The long-term fuel supply plans recognize

[1] The Bridger Coal Company and the Jim Bridger Plant are jointly owned and fuel supply and/or mining operations decisions must be made jointly.
[2] *In the Matter of Pacific Power & Light Company*, Docket No. UE 21, Order No. 84-898 (Nov. 14, 1984); *In the Matter of Idaho Power Company*, Docket No. UI 107, Order No. 91-567 at 4 (Apr. 29, 1991).
[3] *In the Matter of PacifiCorp*, Docket No. UI 189, Order No. 01-472 at 2 (June 12, 2001); *In the Matter of Idaho Power Company*, Docket No. UI 107, Order No. 91-567 at 4 (Apr. 29, 1991); *In the Matter of the Application of Pacific Power & Light Company for an Order Authorizing It to Enter into Agreements with Energy West Company*, Docket No. UI 105, Order No. 91-513 (Apr. 12, 1991).
[4] *In the Matter of PacifiCorp d/b/a Pacific Power 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 6-7 (Oct. 28, 2013).
[5] *Id.* at 6.

that, given the nature of coal mining operations, a multi-year assessment of coal supply costs is more appropriate than an annual review.[6]

2. **Contents of Long-Term Fuel Supply Plans.** PacifiCorp will prepare long-term fuel supply plans to address the economics of continued coal supply from BCC for the Jim Bridger plant and from EWMC to the Huntington and Hunter plants. The form and content of the fuel supply plans may vary from year to year, but the plans will always retain the objective of determining the least-cost, least-risk coal supply. The long-term fuel supply plans will:

    - Use best available data to determine the least-cost, least-risk coal supplies for the plants;
    - Review fueling options for the plants and prepare least-cost mine plans for the key options;
    - Review data on market costs for alternative coal supplies and transportation and the costs associated with plant modifications necessary for alternative fuel supplies; and
    - Review and compare fuel supply options with sensitivities.

3. **Initial Fuel Supply Plans for Jim Bridger, Huntington and Hunter.** PacifiCorp will file the first long-term fuel supply plans for the Jim Bridger, Huntington and Hunter plants in 2015 in a separate docket subject to the Commission's Open Meetings decision-making process (similar to other utility planning dockets).

4. **Future Fuel Supply Plans.** PacifiCorp will update its long-term fuel supply plans once every five years. PacifiCorp will update the plans more often as necessary to address major milestones in coal supply cycles, such as the expiration of third party-coal supply arrangements, major capital investments in the affiliate coal mines, or potential acquisition of new reserves.

5. **Confidential Material.** The long-term fuel supply plans will contain significant confidential information and will require confidential handling. PacifiCorp will request entry of an ongoing protective order for its long-term fuel supply plan dockets, similar to that applicable to TAM proceedings under Order No. 10-069 in docket UE 216.[7]

[6] *Id.* at 15 (Commissioner Savage, concurring).
[7] *In the Matter of PacifiCorp, dba Pacific Power 2011 Transition Adjustment Mechanism*, Docket No. UE 216, Order No. 10-069 (Feb. 25, 2010).

Docket No. UE 307
Exhibit PAC/502
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Dana M. Ralston

Staff Response to PacifiCorp Data Request 11

August 2016

UE 307/OPUC
July 28, 2016
PacifiCorp 2nd Set of Data Requests

PacifiCorp Data Request 11

Refer to Staff/200, Kaufman/24:6-13. Please confirm that Staff's prudence concerns in this case are: (1) limited to the four coal supply and two transport contracts that have a contract starting term of 2015 or later; and (2) based on the current regulatory and economic uncertainty regarding coal generation. Otherwise, please identify the specific contracts Staff believes may be imprudent and a narrative discussion regarding why Staff believes the agreements may not be prudent.

Response to PacifiCorp Data Request 11

The six contracts identified in the referenced testimony were provided for illustrative purposes. Staff's testimony does not claim that these six contracts are either prudent or imprudent. Staff's testimony merely identifies that there is a question as to whether they are prudent, but does not analyze or reach a conclusion on that issue in its testimony. Staff's testimony should also not be read to mean that contracts executed prior to 2015 are prudent. Staff's proposal for the TAM is to exclude elevated coal costs related to minimum take requirements from the 2017 power cost forecast for the three reasons enumerated on Staff/200, Kaufman/22. Staff's testimony argues that the prudence of coal contracts should be addressed in the 2017 PCAM when power costs are trued up. Staff has not analyzed the prudence of specific contracts because Staff's proposal does not require such analysis.

Docket No. UE 307
Exhibit PAC/600
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of R. Bryce Dalley

August 2016

REPLY TESTIMONY OF R. BRYCE DALLEY

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ATTACHED EXHIBITS

Exhibit PAC/601 – Staff's 2009 Pre-GRC Audit

Exhibit PAC/602 – Staff's Discovery Response from docket UE 264

Exhibit PAC/603 – Staff's Response to PacifiCorp Data Requests 6-10

Exhibit PAC/604 – Production Tax Credit details

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

A. My name is R. Bryce Dalley and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as Vice President, Regulation.

QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I received a Bachelor of Science degree in Business Management with an emphasis in finance from Brigham Young University in 2003. I completed the Utility Management Certificate Program at Willamette University in 2009, and I have also attended various educational, professional, and electric-industry-related seminars. I have been employed by PacifiCorp since 2002 in various positions within the regulation and finance organizations. I was appointed Manager of Revenue Requirement in 2008 and was promoted to Director, Regulatory Affairs and Revenue Requirement in 2012. I assumed my current position in January 2014. I am responsible for all regulatory activities in Oregon, Washington, and California.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. My testimony addresses two issues in this case. First, I respond to the adjustments to the cost of coal from the Bridger Coal Company (BCC) proposed in the Opening Testimony filed by Public Utility Commission of Oregon Staff (Staff) witness Mr. Lance Kaufman and the Industrial Customers of Northwest

Utilities' (ICNU) witness Mr. Bradley G. Mullins. I address the regulatory issues raised by these proposed adjustments and, along with Company witness Mr. Dana M. Ralston, support the overall reasonableness of Jim Bridger fuel supply costs in the 2017 Transition Adjustment Mechanism (TAM).

Second, I respond to the Opening Testimony of Staff witness Mr. John Crider on the Company's proposal for tracking changes in renewable energy production tax credits (PTC) in the 2017 TAM, and accept Staff's proposed approach as clarified in discovery. Company witness Ms. Judith M. Ridenour provides additional testimony supporting the Company's modified proposal for tracking changes in PTCs.

Q. Please summarize your reply testimony.

A. My testimony first addresses the appropriate cost recovery standard for BCC coal and demonstrates that both Staff's and ICNU's adjustments rely on the application of novel ratemaking treatment for BCC that lacks any precedential support. BCC has provided substantial customer benefits through a reliable and low-cost supply of coal for over 40 years. During that time, the Public Utility Commission of Oregon (Commission) has consistently applied the same ratemaking treatment to BCC that is applied to all other utility assets—PacifiCorp is authorized to recover its prudent costs, plus a reasonable return. Staff has advocated for and supported this treatment for at least 30 years. Although there have been periodic challenges to BCC coal pricing, the consolidation of BCC with PacifiCorp for ratemaking has been undisputed until this case.

Staff and ICNU argue that BCC coal is more expensive than market alternatives so the Company should replace BCC coal with coal from the Powder River Basin (PRB). But Staff and ICNU reach this conclusion only by ignoring costs that have traditionally been included in rates—such as capital investments at BCC and costs that are eligible for recovery if BCC were to close. To justify its exclusion of these costs, Staff now claims PacifiCorp improperly consolidates BCC for ratemaking. ICNU argues that customers have been improperly subsidizing shareholders by paying a return on the investment in BCC. Both of these positions depart from long-standing ratemaking treatment for BCC. As described by Mr. Ralston, when the correct ratemaking treatment is applied and BCC's costs are properly included in the analysis, the basis for Staff's and ICNU's adjustments are eliminated.

Moreover, both Staff and ICNU rely on a snapshot look at BCC costs for a single year, even though Staff explicitly disavowed this approach in the 2014 TAM, and the Commission approved a long-term fuel plan process. Staff's and ICNU's adjustments improperly rely on hindsight review, an approach Staff also rejected in the 2014 TAM. The Company would have had to made substantial infrastructure investments on an expedited basis beginning in 2014 to replace BCC with PRB coal in 2017. But neither Staff nor ICNU provide any evidence that in late 2013, when the decision would have needed to been made, it would have been reasonable to invest nearly [Begin Confidential] [redacted] [End Confidential] million in the Jim Bridger plant to allow PRB to replace BCC in 2017. Without this evidence, there is no basis for their adjustments.

My testimony also accepts Staff's proposed treatment of PTCs, which results in a more straightforward accounting of PTCs in rates, while achieving the same result as the Company's original proposal.

BACKGROUND ON COAL PRICE ADJUSTMENTS

Q. Please describe Staff's proposed adjustment related to BCC coal costs.

A. Staff contends that the Company's coal costs are imprudent because in a single year—2017—Staff claims that PRB coal is less expensive than coal from BCC. Thus, Staff recommends a disallowance based on the price difference between BCC and PRB coal. Staff's adjustment decreases net power costs (NPC) by $40.9 million (total system), or $10.43 million on an Oregon-allocated basis.[1]

Q. Please describe ICNU's proposed adjustment.

A. ICNU makes a similar argument to Staff, claiming that PRB coal is cheaper in 2017 so the Company should have replaced BCC coal with PRB coal in that single year. ICNU's argument differs from Staff's, however, because ICNU does not contend that the Company was imprudent. Rather, ICNU recommends that the Commission apply the lower of cost or market pricing standard under OAR 860-027-0048 to BCC coal because of BCC's affiliate relationship with PacifiCorp. ICNU claims that PRB coal is a lower cost market alternative and therefore BCC coal should be priced using PRB prices. ICNU's adjustment decreases NPC by $45.7 million (total system), or $11.6 million on an Oregon-allocated basis.[2]

[1] Staff/200, Kaufman/67.
[2] ICNU/100, Mullins/15.

Q. What does the lower of cost or market rule provide?

A. The lower of cost or market rule states that transactions between utilities and affiliates "shall be recorded in the energy utility's accounts at the affiliate's cost or the market rate, whichever is lower."[3] The rule defines "market rate" as "the lowest price that is available from nonaffiliated suppliers for comparable services or supplies."[4]

Q. Has the Commission ever relied on its lower of cost or market affiliate transfer pricing rule to set the transfer price for Jim Bridger coal supply from BCC?

A. No. The Commission has applied the same standard for cost recovery of Jim Bridger fuel costs, including BCC costs, as any other element of the Company's NPC, which is whether the cost is objectively reasonable.

Q. Has the Commission set a cost-based transfer price as a part of approving coal supply arrangements from BCC to the Jim Bridger plant?

A. Yes. For decades, the Commission has allowed PacifiCorp to purchase coal from BCC at the actual, prudent costs of production, plus a return component on the investment in the mine tied to PacifiCorp's current authorized rate of return (ROR).[5] Under this approach, if BCC earns a margin over PacifiCorp's authorized ROR, it must credit this margin back to PacifiCorp (and eventually to customers) through a reduced transfer price.

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[3] OAR 860-027-0048(4)(e).
[4] OAR 860-027-0048(1)(i).
[5] *In the Matter of Pacific Power & Light Company*, Docket No. UF 3508, Order No. 79-754 (Oct. 29, 1979) (reducing transfer price of BCC coal by limiting return to PacifiCorp's authorized ROR); *In the Matter of Pacific Power and Light Company*, Docket No. UF 3779, Order No. 82-606, 49 P.U.R4th 82 (Aug. 18, 1982) (same).

Q. Please identify the orders in which the Commission set this pricing policy.

A. In the Company's 1979 rate case, one of the disputed issues was how to price coal from BCC. In Order No. 79-754, the Commission observed that "staff's ideal coal price would be one permitting [BCC] to recover expenses and earn a fair and reasonable rate of return." [6] In other words, Staff supported the same cost recovery methodology for BCC as for all other utility investments. The Commission adopted Staff's position, finding that PacifiCorp "treats [BCC] as an integral part of its own utility operation and never intended that [BCC] stand independent of the company."[7] Thus, according to the Commission, PacifiCorp is "entitled to recover its costs and a reasonable return on its investment."[8]

The issue of BCC pricing was litigated again in the Company's 1982 rate case. In that case, the Company argued that BCC was not a utility investment and therefore the transfer price should be based on the contract price between PacifiCorp and BCC.[9] In Order No. 82-606, the Commission rejected PacifiCorp's argument and affirmed its conclusion in Order No. 79-754 that PacifiCorp is "entitled to recover its cost for producing the coal and a return on its investment equal to that allowed" for the Company's electric operations.[10]

In both Orders Nos. 79-754 and 82-606, the Commission applied a cost-based approach to PacifiCorp's coal purchases from BCC, setting the transfer

[6] Order No. 79-754 at 17.
[7] *Id.* at 18.
[8] *Id.* at 19.
[9] Order No. 82-606, 49 P.U.R.4th at 87.
[10] *Id.* at 88.

price at the actual, prudent costs of production, plus a return component on the investment in BCC limited to PacifiCorp's current authorized ROR.

Q. Are there more recent orders articulating the objective reasonableness standard for BCC costs?

A. Yes. In the Commission's most recent order approving the affiliate relationship between PacifiCorp and BCC, Order No. 01-472, the Commission expressly approved the contract between BCC and PacifiCorp as "fair, reasonable, and not contrary to the public interest."[11] In that order, Staff recommended that the Commission "review for *reasonableness* all financial aspects of this relationship in any rate proceeding . . ."[12] Staff also noted that from 1990 through 1999, the average cost of coal provided from BCC was $3 to $9 per ton less than the average market price of Southern Wyoming coal delivered to the plant.[13]

Q. Has the Commission taken additional steps to ensure that customers' interests are protected in PacifiCorp's coal supply arrangements with its affiliate mining companies?

A. Yes. The Commission consolidated PacifiCorp's affiliate coal mining companies with PacifiCorp's regulated operations for regulatory purposes.[14] This consolidation is clearly articulated in Order No. 84-898 from the Company's 1984 rate case. In that case, Staff proposed an adjustment related to the tax treatment of BCC, arguing that the Company's use of a separate tax return for BCC was

[11] *In the Matter of PacifiCorp*, Docket No. UI 189, Order No. 01-472 at 2 (June 12, 2001).
[12] *Id.*, App. A at 4.
[13] *Id.*, App. A at 2.
[14] *In the Matter of Pacific Power & Light Company*, Docket No. UE 21, Order No. 84-898, 63 P.U.R.4th 642 (Nov. 14, 1984).

"inconsistent with the [Commission's] past practice of consolidating the subsidiary into Pacific's electric results of operations."[15] Staff eventually withdrew its adjustment upon further review of the applicable tax code, and the Commission confirmed that even though Staff withdrew its adjustment, it "does not mean that staff has departed from the general policy of consolidating the [BCC] subsidiary."[16]

Because BCC's results are merged with and made a part of PacifiCorp's for ratemaking, there is no possibility of cross-subsidization. In this way, BCC is not treated as an affiliate at all; it is treated as if PacifiCorp itself were mining the coal.

Q. Have capital investments in BCC been recovered in rates?

A. Yes. For example, in docket UE 170, the Company's 2005 general rate case, the Commission approved a stipulation that specifically allowed recovery of capital expenditures associated with development of the underground operations at BCC.[17] More recently, the revenue requirement in the Company's last general rate case, docket UE 263, included capital investments in the BCC mine, including investments in equipment, mine development, and materials and supplies.[18]

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[15] *Id.* at *8.
[16] *Id.*
[17] *See Pacific Power & Light Co. Request for General Rate Increase*, Docket No. UE 170, Order No. 05-1050 at 6 (Sept. 28, 2005); Docket No. UE 207, PPL/202, Lasich/3-4.
[18] Docket No. UE 263, PAC/1002, Tawwater/8.3. Docket UE 263 was resolved by a stipulation that did not specifically address the BCC investments included in the Company's filing. Nonetheless, no party objected to those investments and none of the identified adjustments to the Company's direct filing involved the BCC investments.

Q. Has the Commission applied similar regulatory treatment to PacifiCorp's other affiliate mines?

A. Yes. Like BCC, the Company's other mining affiliate, Energy West Mining Company (EWMC), which operated the Deer Creek mine, was also consolidated with PacifiCorp for ratemaking purposes and not treated as an affiliate.[19] In Order No. 91-513, the Commission approved the mining contract between PacifiCorp and EWMC on a cost-based approach, finding that the "cost-based approach and the limitation of EWMC's activities to those arising under the contract minimize the likelihood of cross-subsidization."[20] The Commission continued, "[t]hrough the rate-making process, the Commission can ensure that Oregon utility customers do not pay unreasonable expenses."[21]

The Commission confirmed this treatment of the Deer Creek mine when it recently issued an order addressing several ratemaking issues implicated by the closure of the mine. In Order No. 15-161, which addressed cost recovery of undepreciated investments at the mine and closure costs, the Commission treated the mine the same as any other utility asset and allowed recovery after finding that closure was in the public interest.[22]

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[19] *See e.g.*, *Re PacifiCorp*, Docket No. UI 105, Order No. 91-513 (Apr. 12, 1991).
[20] *Id.* at 2; *see also In the Matter of Pacific Power & Light Company d/b/a PacifiCorp*, Docket No. UI 249, Order No. 06-305 at App. A at 3 (June 19, 2006) ("The Commission, in Order No. 91-513 (UI 105), has previously allowed a cost-based approach, instead of the lower of cost or market standard pursuant to OAR 860-027-0048, when affiliate activities were limited to a specific contract function.").
[21] Order No. 91-513 at 2.
[22] *See In the Matter of PacifiCorp Application for Approval of Deer Creek Mine Transaction*, Docket No. UM 1712, Order No. 15-161 at 7-8 (May 27, 2015).

Q. Has Staff acknowledged the Commission's regulatory treatment of BCC?

A. Yes. In 2009, Staff confirmed this treatment of BCC and EWMC in its pre-rate case audit of PacifiCorp, when Staff wrote that, "Commission orders concerning affiliated interest contracts with [BCC] and [EWMC] allow for cost-based pricing of coal from these affiliates."[23] Staff continued that this approach is an "approved departure from OAR 860-027-0048 . . . which normally requires the lower of cost or market standard when a utility is purchasing goods or services from an affiliate."[24]

Q. Has the Commission applied similar regulatory treatment to the co-owner of BCC, Idaho Power Company (Idaho Power)?

A. Yes. In Order No. 91-567, the Commission approved the coal sales agreement between BCC and Idaho Power noting that transactions are "technically" subject to the affiliated interest filing requirements even though the Idaho Power subsidiary that is a one-third owner of BCC is "disregarded as a separate entity for ratemaking purposes."[25] The Commission also found that there is no risk of cross-subsidization between Idaho Power and BCC, "nor is there any danger of Idaho [Power] paying in excess of market value" because Idaho Power is "paying for its coal as if [the affiliate] were not even involved in [the] transaction."[26] The Commission also found that the transfer price for coal "shall be billed at the actual

[23] PAC/601, Dalley/5.
[24] PAC/601, Dalley/5.
[25] *Re Idaho Power Co.*, Docket No. UI 107, Order No. 91-567 at 2 (Apr. 25, 1991).
[26] *Id.*

cost" and that BCC coal had and "will continue to provide a reliable source of low-cost coal for the operation of Jim Bridger plant."[27]

Q. Have BCC costs been litigated in recent TAM proceedings?

A. Yes. In the Company's 2010 TAM (docket UE 207), BCC costs increased because a new accounting standard required the Company to expense coal in 2010 if the coal was uncovered but not extracted, and because of greater reclamation activity at the mine. Staff recommended that the Commission apply the lower of cost or market standard to BCC coal and claimed generally that coal from the Black Butte mine, the Kemmerer mine,[28] and the PRB was lower cost than BCC coal. In response, the Company presented evidence demonstrating that there were insufficient supplies of coal from Black Butte and Kemmerer to offset BCC volumes and that a correct cost of coal from those mines, including transportation, exceeded BCC's costs.

Regarding PRB coal, the Company demonstrated that the cost of PRB coal, inclusive of transportation, was more than [Begin Confidential] $[redacted] [End Confidential] per ton higher than BCC coal.[29] The Company also explained that the Jim Bridger plant "lacks the physical capacity to accept significant new volumes of rail delivered coal."[30] Therefore, use of PRB coal at the Jim Bridger plant would require "significant new infrastructure investments to its receiving facilities," which were not justified based on BCC coal prices at that time.[31]

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[27] *Id.* at 3.
[28] The Kemmerer mine served the Naughton plant and is also located in Southwest Wyoming.
[29] Docket No. UE 207, Staff/200, Dougherty/17.
[30] Docket No. UE 207, PAC/400, Morgan/14.
[31] Docket No. UE 207, PAC/400, Morgan/14.

The Company further argued that it was unreasonable to apply the lower of cost or market standard to annual cost fluctuations. Instead, the Company recommended that the Commission take a long-term approach when determining the reasonableness of the Jim Bridger plant's fuel supply costs.

Q. In that case, did the Company explain how BCC coal supply reduced market risk to customers?

A. Yes. The Company testified that BCC provided an important hedge against rising costs in the market and potential disruptions in deliveries that might be caused by rail transportation issues. The Company pointed to Staff's 2009 pre-rate case audit, referred to above. In that audit, Staff observed that regional coal market prices were comparable to BCC's mine costs and that, as of 2009, "soaring demand" was expected to cause PRB prices to "spike."[32] As a result, Staff concluded that "having captive mines may result in an increasing benefit to PacifiCorp's customers."[33]

Q. How was the 2010 TAM resolved?

A. The parties ultimately settled that case with no specific resolution of the BCC coal cost issue.

Q. What happened in subsequent TAMs?

A. In the next two TAMs, dockets UE 216 and UE 227, the Company submitted evidence that BCC remained lower cost compared to available alternatives, including PRB coal. In the 2011 TAM (docket UE 216), BCC costs decreased, while Black Butte costs increased, resulting in BCC being the lower cost. The

[32] PAC/601, Dalley/4.
[33] PAC/601, Dalley/5.

Company also testified that PRB coal was priced at nearly [Begin Confidential] $[redacted] [End Confidential] more per ton than BCC, without accounting for the capital modifications required to receive PRB coal. The Company's testimony also discussed the impact of reclamation activity on BCC's cost-based prices and analyzed the impact of closing the surface mine, demonstrating that doing so was uneconomic because the costs of the undepreciated surface investments would flow into the coal costs from the underground operation.

In both dockets UE 216 and UE 227, Staff conducted its own analysis and confirmed that BCC was lower in cost than market alternatives. No party challenged the reasonableness of the Company's coal costs in either of those two cases.

Q. Did ICNU challenge BCC costs in the 2014 TAM, docket UE 264?

A. Yes. ICNU proposed application of lower of cost or market pricing to BCC coal. In that case, the BCC coal was priced at [Begin Confidential] $[redacted] [End Confidential] per ton, while Black Butte coal was priced at [Begin Confidential] $[redacted]ton, [End Confidential] a difference of roughly [Begin Confidential] [redacted] [End Confidential] percent.[34] The increase in BCC costs in that case was largely attributable to increased reclamation activity at the mine.[35]

In response to ICNU's adjustment, PacifiCorp explained that there were insufficient volumes available from the Black Butte mine and therefore the Company could not replace BCC coal with an alternative supplier.

[34] Docket No. UE 264, PAC/600, Crane/9 (BCC at $37.94/ton and Black Butte at $36.95/ton).
[35] Docket No. UE 264, PAC/600, Crane/9-10.

PacifiCorp also proposed that it file periodic long-term fuel plans to allow for a fair and reasonable multi-year comparison of affiliate and alternative coal supplies in future TAMs to move away from recurring litigation based on an examination of coal costs in a single year.[36]

Q. What position did Staff take in the 2014 TAM?

A. Staff did not support ICNU's adjustment. Instead, Staff supported the traditional cost-based approach that had been used by the Commission since the 1970's and recommended "rate-case type adjustment" to several O&M expense categories at the mine.[37] Staff's adjustment was implicitly premised on the understanding that BCC was wholly consolidated with PacifiCorp for ratemaking purposes and was therefore subject to rate case adjustments like other aspects of PacifiCorp's operations.

Staff also rejected the notion of analyzing the prudence of the Company's coal supply from affiliate mines on a year-by-year basis as coal supply costs fluctuate in annual NPC updates.[38] Rather, Staff supported a long-term view and indicated that the prudence standard should compare the "affiliate mine fuel plan to other alternative fuel plans, including market alternatives, which are known to be available at the times when the Company is deciding whether to continue or extend operations at the affiliate mines."[39] Importantly, Staff emphasized that this examination should not rely on hindsight review, but must be based on what the

[36] *In the Matter of PacifiCorp's 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 7 (Oct. 28, 2013).
[37] *Id.*
[38] PAC/602, Dalley/1.
[39] PAC/602, Dalley/1.

Company knew or should have known at the time the relevant decisions were made. Staff supported the Company's proposal to file periodic fuel supply plans as a way to facilitate this review of affiliate costs, as did the Citizens' Utility Board of Oregon.

Q. How did the Commission resolve ICNU's adjustment in the 2014 TAM?

A. The Commission rejected ICNU's recommendation, finding that the Company demonstrated that its approach to the coal supply for the Jim Bridger plant was "fair, just, and reasonable."[40] The Commission found that, while BCC and Black Butte mine prices have fluctuated over the years, *over the long-term* they have both provided a reasonably priced, stable coal supply.[41]

The Commission also found that ICNU's re-pricing approach was unpersuasive because the Company demonstrated that additional low-cost Black Butte coal was not actually *available* during the test period.[42] Thus, the Commission found that it is not enough to simply show that cheaper coal exists in the market if that cheaper coal could not physically replace BCC coal.

Commissioner Savage offered a concurring opinion, in which he wrote that given the nature of coal mining operations, BCC costs "must be assessed over a period of years, and not yearly as proposed by ICNU."[43] Thus, the Commission also adopted the proposal for the Company to file periodic fuel supply plans to

[40] Order No. 13-387 at 6.
[41] *Id.*
[42] *Id.* at 7.
[43] *Id.* at 15.

compare affiliate mine costs to alternative supply options, including market alternatives.[44]

Q. How did the Commission resolve Staff's rate-case type adjustment for BCC in the 2014 TAM?

A. The Commission approved Staff's adjustment to BCC costs in docket UE 264 and the Company has implemented it in subsequent TAMs, including this case.

Q. What were the prices of BCC and Black Butte coal supply in the 2015 and 2016 TAMs?

A. In the 2015 TAM (docket UE 287), Black Butte costs increased to [Begin Confidential] $[redacted] [End Confidential] per ton, while BCC costs increased to [Begin Confidential] $[redacted] [End Confidential] per ton, remaining within roughly one percent of one another.[45] In the 2016 TAM (docket UE 296), Black Butte prices increased to [Begin Confidential] $[redacted] [End Confidential] per ton, while BCC costs increased to [Begin Confidential] $[redacted] [End Confidential] per ton.[46] These prices again confirmed the comparability of BCC to market alternatives.

Q. How did the Company implement the Commission's direction to file periodic fuel supply plans?

A. Following the Commission's approval of the proposal in the 2014 TAM, in the 2015 TAM (docket UE 287), PacifiCorp filed a compliance proposal describing the purpose and content of periodic fuel supply plans for its affiliate mines.[47]

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[44] *Id.* at 7.
[45] Docket No. UE 287, PAC/200, Crane/11.
[46] Docket No. UE 296, PAC/300, Larsen/8, 15.
[47] Docket No. UE 287, PAC/201.

The compliance proposal stated that "long-term fuel plans recognize that, given the nature of coal mining operations, a multi-year assessment of supply costs is more appropriate than an annual review."[48] The proposal for filing long-term fuel plans was designed to facilitate the review of prudence and affiliated interest standards in future rate cases by allowing a multi-year assessment of the Company's fuel supply plan in a utility planning docket, rather than in a contested case.[49]

The Company implemented this proposal in December 2015, by filing a Long-Term Fuel Plan for the Jim Bridger plant. No party objected to the Company's compliance proposal or filing at the time. In his reply testimony, Mr. Ralston describes the Company's Long-Term Fuel Plan and its consistency with the Jim Bridger fuel supply plan in the 2017 TAM.

RESPONSE TO COAL PRICE ADJUSTMENTS

Q. Are the parties' BCC adjustments in this case consistent with the regulatory framework set by the Commission, requiring a cost-based, multi-year review of the Company's fuel supply plan for the Jim Bridger plant?

A. No. The adjustments are similar to past adjustments that challenged fuel supply costs at the Jim Bridger plant based on a single-year comparison of BCC costs and alleged market alternatives. The Commission has never approved this type of adjustment. In the 2014 TAM, the Commission made clear that it would review the prudence of fuel supply at the Jim Bridger plant on a long-term basis, not using the single-year snapshot proposed by the Staff and ICNU in this case.

[48] Docket No. UE 287, PAC/201, Crane/1-2.
[49] Docket No. UE 287, PAC/201, Crane/1.

Q. Does Staff agree that BCC is consolidated with PacifiCorp for purposes of ratemaking?

A. No. Staff presents a novel position in this case that the Company improperly treats BCC costs as pass through costs by consolidating BCC with PacifiCorp for ratemaking.[50] Staff specifically claims that in Orders Nos. 79-754, 82-606, and 01-472, the Commission made clear that the relationship between PacifiCorp and BCC is governed by contract and the contract is the basis for recovery of BCC costs in customer rates.[51] As discussed above, however, Staff's position here was specifically rejected by the Commission in Order No. 82-606, a result that has been repeatedly affirmed. Therefore, prudently incurred BCC costs are passed through to customers as if PacifiCorp itself were incurring those costs. Although the Commission recognized the contract between the Company and BCC, transfer pricing was *not* based on the terms of the contract.[52]

Q. How does Staff's new position on the ratemaking treatment of BCC costs impact its adjustment here?

A. Staff contends that if the Company stopped purchasing BCC coal, there would be no incremental costs because customers are not responsible for closure costs and undepreciated assets.[53] Therefore, Staff's analysis fails to consider these costs when it recommends that PRB coal should replace BCC coal.

[50] Staff/200, Kaufman/48.
[51] Staff/200, Kaufman/49-50.
[52] Accordingly, Staff is wrong to fault the Company for departing from the strict pricing terms of its contract with BCC. Staff/200, Kaufman/30.
[53] Staff/200, Kaufman/56, 63.

Q. Does ICNU's analysis also ignore unrecovered investment costs when comparing BCC to PRB costs?

A. Yes. ICNU argues that PacifiCorp's shareholders have earned "substantial returns" on their investment in BCC and that one of the risks shareholders assumed was that they would have to dispose of mining assets for a loss.[54]

Q. Is there any basis to ignore these costs when comparing the costs of fuel supply from BCC and PRB?

A. No. The fact that BCC is fully consolidated with PacifiCorp for ratemaking purposes means that customers are responsible for all of the prudently incurred closure and remediation costs, just as customers are responsible for prudently incurred closure and remediation costs associated with all other utility plant. Customers have received the long-term benefit of BCC coal and should pay the full costs of the resource.

The costs of closure activities and reclamation have traditionally been included in BCC's coal price without objection from parties or the Commission.[55] The Company has also consistently accounted for the impact of undepreciated investment when analyzing alternatives to BCC, as discussed above.

Q. Is there any precedent for PacifiCorp recovering closure costs and undepreciated investments in affiliated mines?

A. Yes. Staff's and ICNU's position here is at odds with the Commission's recent Order No. 15-161, where the Commission addressed several ratemaking issues related to the Company's closure of its Deer Creek mine. In that order, the

[54] ICNU/100, Mullins/15.
[55] *See e.g.*, Docket No. UE 264, PAC/900, Crane/9-10.

Commission approved PacifiCorp's recovery of the undepreciated investment in the mine because closure was in the public interest, and allowed PacifiCorp to defer for later recovery the closure costs associated with the mine.[56] Like Deer Creek, if early closure of BCC is in the public interest, then PacifiCorp is entitled to recover the undepreciated investment.

Q. How do closure costs and undepreciated investments impact Staff's and ICNU's adjustment?

A. As described in Mr. Ralston's testimony, if Staff and ICNU had properly accounted for these costs (among others ignored by Staff and ICNU), then the cost of PRB coal is higher than the cost of a fuel plan using BCC coal in 2017. Thus, even if a single-year look is appropriate, there is no basis for Staff's or ICNU's adjustment.

Q. Staff also claims that the reasonableness of BCC costs has generally been assessed by comparing BCC to available market alternatives.[57] Do you agree?

A. Yes. Both the Company and the Commission have consistently compared BCC costs to available market alternatives in order to assess the reasonableness of BCC costs. But, to be clear, the Commission has never strictly applied the lower of cost or market standard to BCC coal.

[56] Order No. 15-161 at 6-8.
[57] Staff/200, Kaufman/51.

Q. Is Staff's position here consistent with its past standard for reviewing the prudence of the Company's long-term fuel plans?

A. No. Following several TAMs where Staff conducted an annual review of BCC costs, rather than a multi-year look, in docket UE 264 Staff modified its approach and agreed with PacifiCorp that BCC costs must be evaluated over the long-term. That agreement ultimately led to the preparation and filing of the Long-Term Fuel Supply Plan. In this case, however, Staff has effectively reverted to an annual look, claiming that in 2017, BCC coal costs are higher than PRB coal costs. Without consideration of the Company's Long-Term Fuel Plan, Staff asserts that the Company is imprudent for not replacing BCC coal with PRB coal for 2017. As discussed by Mr. Ralston, however, even applying Staff's new standard for review of BCC costs, the evidence does not support Staff's adjustment.

Q. Does Staff's position rely in hindsight review?

A. Yes. As described in the Long-Term Fuel Plan, and in Mr. Ralston's testimony, in order for PRB coal to replace BCC coal in 2017, the Company would have had to begin construction on an expedited basis for the facilities necessary to receive and burn large quantities of PRB coal no later than the beginning of 2014. Thus, Staff effectively relies on hindsight when it implicitly claims that the Company should have known years ago that PRB coal would be least cost in 2017, even though the undisputed evidence shows that until this year no party questioned the prudence of the Company's fueling strategy. Indeed, the Commission issued Order No. 13-387 in 2013—the year the Company would have had to decide to transition to PRB coal—and specifically found (with Staff's support) that the

Company's fueling strategy for the Jim Bridger plant was prudent. During that same time period, the Commission also approved a stipulated revenue requirement including new capital investments at BCC in PacifiCorp's general rate case, docket UE 263.

RESPONSE TO STAFF'S PTC PROPOSAL

Q. Please describe the Company's proposed treatment of PTCs in this case.

A. Mr. Brian S. Dickman's direct testimony includes the Company's proposal to implement Section 18(b) of Senate Bill 1547.[58] The Company's NPC calculation in the 2017 TAM includes the variance between PTCs currently in base rates, as established in the Company's last general rate case, docket UE 263, and the forecast PTCs for 2017. The Company also proposed to track variances in forecast and actual PTCs though the Company's annual power cost adjustment mechanism (PCAM).

Q. Did Staff support the Company's proposal?

A. No. Staff testified that the Company's proposal is overly complicated because it requires annual tracking of the difference between PTCs in base rates and those projected in the TAM, and the difference between the projected and actual PTCs in the PCAM.[59] As clarified during discovery, Staff proposes a simplified approach by resetting PTCs in base rates to zero, eliminating the need to calculate future variances between PTCs in base rates and PTCs in the TAM forecast.[60]

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[58] PAC/100, Dickman/5-6.
[59] Staff/100, Crider/20.
[60] Staff/100, Crider/21; PAC/603 (Staff Responses to PacifiCorp Data Requests 6-10).

Then, Staff proposes to include the full PTC forecast in the TAM, subject to true-up in the PCAM. Staff testified that it supported a similar approach for Portland General Electric Company (PGE) in docket UE 308.

Q. Does the Company support Staff's alternative approach?

A. Yes. The Company agrees that Staff's approach is less complex, achieves the same end result, and provides general uniformity in PacifiCorp's and PGE's implementation of this provision of Senate Bill 1547.

Q. Does Staff's approach impact proposed rates for the 2017 TAM?

A. No. There is no change in the incremental increase in revenue requirement resulting from Staff's approach because it ultimately reflects the same level of PTCs as in the Company's initial filing. The difference is that under Staff's approach, the PTC level included in the Company's last general rate case is removed entirely from base rates (Schedule 200) and the full forecast of PTC for 2017 is reflected in variable NPC (Schedule 201).

Q. How would this effect rates under those schedules?

A. Staff's proposal would result in an initial increase in rates under Schedule 200 and a decrease in rates under Schedule 201, adjusted for the current forecasted level of PTCs in the test period. Going forward, PTCs would be a forecast element in calculating rates under Schedule 201, and the expiration of PTCs would be reflected in future forecasts.

Q. Does adopting Staff's approach result in any change in the Company's revenue requirement relative to the Company's original proposal?

A. No. The result is summarized in Table 1 below. The level of PTCs currently in rates is adjusted to account for the change in load since docket UE 263. This results in approximately a $5.0 increase in revenue requirement.

Table 1

Oregon Allocated Production Tax Credits ($millions)	
PTC Revenue Requirement in Rates from UE 263	($27.6)
Change due to Load Variance from UE 263	$0.5
2017 PTC in rates	($27.1)
PTC Revenue Requirement for 2017	($22.1)
Increase Absent Load Change	$5.5
Increase Including Load Change	$5.0

Adopting Staff's approach would result in the same change in overall revenue requirement as the Company's original proposal.[61] Additional detail is provided in Exhibit PAC/604.

Q. Does adopting Staff's approach affect the calculation of the transition adjustments?

A. Yes. The transition adjustments are calculated by comparing the Schedule 201 rates to the value of freed up energy in the TAM. Holding all else constant, the reduction in Schedule 201 rates due to the inclusion of PTCs will cause the transition adjustments to be higher. For multi-year direct access programs (i.e. the 3- and 5-year programs) the projected Schedule 201 rates will include a

[61] *See* PAC/100, Dickman/5:1-20 and PAC/106.

forecasted level of PTCs in the calculation of the transition adjustments that recognizes the expiration of PTCs at various wind resources over time.

Q. Will the forecast of PTCs affect the consumer opt-out charge for the 5-year direct access option?

A. Yes. The consumer opt-out charge is based on the present value of Schedule 200 rates and projected transition adjustments for years 6 through 10 after a customer elects to participate in the 5-year direct access program. The projected transition adjustment will include the impact of PTCs expiring over that time period.

Q. Has the Company filed revised tariffs in this case to implement Staff's proposed approach to tracking changes in PTCs?

A. Yes. The testimony of Company witness Ms. Ridenour describes in more detail the tariff changes required to implement Staff's approach to updating PTCs in the TAM.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 307
Exhibit PAC/601
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of R. Bryce Dalley

Staff's 2009 Pre-GRC Audit

August 2016

Docket No. UE-207
Exhibit PPL/203
Witness: A. Robert Lasich

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-surrebuttal Testimony of A. Robert Lasich

Excerpt of Staff Audit Report
March 11, 2009

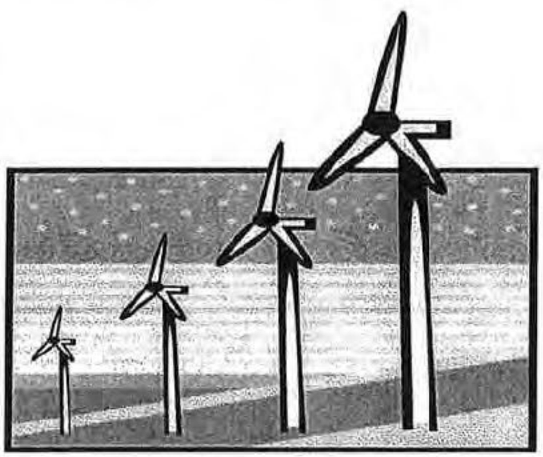
September 2009

Staff Audit Report of

PacifiCorp

Audit Number: 2008-002

March 11, 2009



Audit team: Dustin Ball (Lead Auditor)
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Corporate Services/Cost Allocation Manual

Pursuant to OAR 860-027-0048, PacifiCorp provided Staff a Cost Allocation Manual (CAM) as an attachment to its 2007 Affiliated Interest Report. Staff reviewed the content and format of the CAM and believes that PacifiCorp has adequately addressed its cost allocation methods.

Coal Purchases from Affiliates

PacifiCorp purchases coal from certain affiliates, Bridger Coal Company, Energy West Mining Company, and Trapper Mining Company. The Bridger Mines provides coal to the Jim Bridger plant, of which PacifiCorp owns 66.7 percent. The Jim Bridger plant is located in Wyoming. According to the Company, the transition of Jim Bridger Coal Company from surface mining operation to a combined underground/surface mining operation has resulted in an increase in costs and a shift in cost drivers. As a result in the change in operation, coal costs from Jin Bridger have increased.

Energy West Mining Company's Deer Creek Coal Company (underground mining method) provides coal for the Company's Carbon, Hunter, and Huntington Plants, which are located in Utah. According to PacifiCorp, coal costs have increased from 2006 to 2008 due to a number of factors including labor and benefit costs, materials and supplies, mine maintenance, and professional services.

PacifiCorp is also a minority owner of Trapper Mining Inc. (21.4 percent). Trapper Mining Inc. provides coal to PacifiCorp's Craig Plant, which is located in Colorado. According to PacifiCorp's 10-K, the Craig Plant is supplied from coal produced from a surface mining operation.

The following tables shows Bridger Coal Company (Underground/Surface), Deer Creek Coal Company (Underground), and Trapper Mining Coal Company (Surface) coal costs for 2006 through 2008. The table also for illustrative purposes shows coal costs for PacifiCorp coal plants not supplied by affiliates. Unless specified, the coal costs do not include transportation costs.

Table 25 – Coal Costs, 2006 - 2008

	2006	2007	2008	Change 2006 - 2008
Coal Purchased from Affiliates				
Bridger Coal – Wyoming (Combined)	$20.77	$23.59	$29.37	41.41%
Deer Creek Coal – Utah (Carbon, Hunter, Huntington - Underground)	$23.93	$26.27	$25.08	4.81%

Trapper Coal Base – Colorado (Craig - Surface)	$22.68	$24.43	$25.57	12.74%
Trapper Coal Spot – Colorado (Craig - Surface)	$22.50	$20.60	$29.88	32.8%

Coal Purchased from Third Parties				
Coal supplied to Cholla - Arizona (Surface)	$24.05	$24.24	$27.52	14.43%
Dave Johnston – Wyoming (Surface)	$5.34	$5.83	$7.14	33.71%
Dave Johnston – Wyoming with Transportation	$9.99	$10.52	$12.09	21.02%
Wyodak – Wyoming (Surface)	$10.59	$10.81	$11.49	8.50%
Naughton – Wyoming (Surface)	$25.04	$27.46	$26.86	7.27%
Colstrip – Montana (Surface)	$14.46	$15.80	$17.27	19.43%
Hayden – Colorado (Combined)	$31.38	$33.43	$34.03	17.27%
Hayden – Colorado with Transportation	NA	NA	$36.80	NA

The following table highlights market prices.

Table 26 - DOE/EIA 2007 Info Average sale price ($ per Short Ton)

State	2006 Underground	2006 Surface	2007 Underground	2007 Surface
Colorado	$24.10	$24.70	$24.91 (Total)	Not listed
New Mexico	$29.15 (Total)	Not Listed	$29.91 (Total)	Not listed
Utah	$24.98	Not listed	$25.69	Not listed
Wyoming	Not Listed	$9.03	Not Listed	$9.67 (Open) 13.62 (Captive)

** Information received from PacifiCorp based on Platt's indicates that 2008 average Colorado coal price was $34/ton, a significant increase from the 2007 level. Additionally, 2008 average Utah coal price was $28.41, also a significant increase from the 2007 level.*

The DOE/EIA prices exclude silt, culm, refuse bank, slurry dam, and dredge operations. The DOE/EIA did not include a price for underground operations in Wyoming (withheld to avoid disclosure), but the average 2007 market price for underground operations in Utah was listed at $25.69 and the average 2007 market price for total operations in Colorado was listed as $24.91.

The market prices in these neighboring states are comparable to PacifiCorp's 2007 costs for underground and combined operations (Bridger - $23.59; and Deer Creek - $26.27). The 2008 Deer Creek cost of $25.08 reflects a $1.19/ton decrease in cost from the 2007 level resulting in considerably lower than market levels ($28.41) in 2008. As noted by FERC Market Snapshot Regional Coal Spot Prices, Utah and Colorado coal prices have risen sharply in 2008.

In a response to a Staff data request, PacifiCorp stated that all power plants are typically designed and constructed to consume a typical range of coals. As an example, the Hayden Plant consumes Colorado coals, which are normally bituminous, while other plants (Jim Bridger, Dave Johnston, Wyodak, and Colstrip) consume sub-bituminous coals. The following table highlights the Btu/lb of coal used by PacifiCorp plants

Table 27 – Heat Content of Coals used by PacifiCorp Plants

Mines	Btu/lb
Hayden (Colorado)	10,500 – 11,300 Btu/lb
Dave Johnston, Wyodak and Colstrip (PRB)	8,000 – 8,800 Btu/lb
Jim Bridger (Green River Basin – Wyoming)	9,200 – 10,000 Btu/lb

According to its website, the DOE/EIA lists Powder River Basin (PRB) spot cost per short ton, as of November 7, 2008, as $14.50. The website does not distinguish between underground and surface operations as there appears to be a lack of historical pricing for Wyoming underground operations. (Bridger is currently the only underground mine operation in Wyoming.) However, it should also be noted that the cost of PRB coal is expected to increase due to rising costs of Appalachian coal. According to Mineweb.com[9]:

> Soaring demand for coal and spiking prices should open new markets at home -- and to a lesser extent overseas -- for low-cost, low-sulfur coal from Wyoming's Powder River Basin, providing a boost for the miners that produce it and the railroads that move it.

The article also points out:

[9] http://www.mineweb.com/mineweb/view/mineweb/en/page38?oid=54526&sn=Detail

> PRB coal is the world's cheapest source of electricity," said Dan Scott, director of equity research at investment bank Dahlman Rose. "In today's market, that creates interesting opportunities for miners and the railroads hauling the coal.

As a result of potential rising costs, having captive mines may result in an increasing benefit to PacifiCorp customers. This is not a foregone conclusion and costs and cost trends would need to be examined during subsequent rate filings.

Transfer Pricing

Commission orders concerning affiliated interest contracts with Bridger (Order No. 01-472, UI 189) and Energy West (Deer Creek, Order No. 91-105, UI 105) allow for cost-based pricing of coal from these affiliates. This is an approved departure from OAR 860-027-0048, Allocation of Costs by an Energy Utility, which normally requires the lower of cost or market standard when a utility is purchasing goods or services from an affiliate.

ORS 757.495, Contracts involving utilities and persons with affiliated interests, requires the Commission to approve the contracts if the Commission finds that the contracts are fair and reasonable and not contrary to the public interest. In both the Bridger and Energy West contracts, the Commission found that the contracts were fair and reasonable and not contrary to the public interest.

However, concerning approval of affiliated interest contracts, the Commission does not need to determine the reasonableness of all the financial aspects of the contract for ratemaking purposes. The Commission can reserve that issue for a subsequent proceeding. The subsequent proceeding in this case would be the Company's TAM or general rate filing.

Concerning transfer pricing in UI 189, Staff's memo states:

> If there should be a further lowering of the savings to PacifiCorp and its customers, it may necessitate a modification to the transfer price to meet the Commission's AI policy. This would then require PacifiCorp to comply with proposed ordering condition No. 3 to protect the public's interest.

Deer Creek Mine

Based on a comparison, the average 2007 market price in Utah (underground) of \$25.69 was lower than PacifiCorp's coal costs concerning Deer Creek underground (\$26.27). However; as previously mentioned, the 2008 Deer Creek cost of \$25.49 reflects a decrease in costs from the 2007 level resulting in slightly lower than market levels (\$25.69). If 2008 Deer Creek costs are actually determined to be below market and maintained at below market, this would result in a benefit to customers.

Trapper Mining

Concerning Trapper Mining, the 2007 market price for total operations in Colorado ($24.91) is higher than the Trapper Mining 2007 cost for base ($24.43) and spot ($20.63) purchases. Additionally, 2008 third-party coal costs for PacifiCorp's Hayden Plant in Colorado was significantly higher ($34.03) than the Trapper Mining 2008 cost for base ($25.57) and spot ($29.88) purchases. As a result, Trapper Mining costs actually appear are clearly below market cost, which results in a benefit to customers.

Bridger Coal

As previously mentioned, Bridger is a combined surface/underground mining operation. The following table highlights the change in operation of Bridger from a predominantly surface operation to a predominantly underground operation from the 2006 through 2008 time period.

Table 28 – Bridger Mining Operations

	2006	2007	Through September 2008
Surface Operations – Tons (000)	5,646.0	3,139.4	1,745.0
Surface Operations - $/Ton	$18.490	$18.354	$24.467
Underground Operations – Tons	422.3	2,644.9	2,471.8
Underground Operations – $/Ton	$51.24	$29.812	$34.185

The 2008 Bridger combined underground/surface cost ($28.34) as well as underground cost ($34.19) are comparable to the 2008 underground mining for Utah ($28.4) and Colorado ($34.00). The Bridger 2008 surface coal cost ($24.467) is considerably higher than two other PacifiCorp's Wyoming plants (Dave Johnston ($12.09 with transportation), Wyodak ($11.49), but actually lower than coal cost at Naughton ($26.86). It should be noted that Bridger is located in Southwest Wyoming's Green River Basin (GRB). According to information furnished by PacifiCorp, there are only three coal mines operating in the GRB.

Additionally, it should be noted that PacifiCorp Bridger costs are higher than the Wyoming overall market costs. Unfortunately, because Bridger is the only underground mining operations in Wyoming, comparative cost studies can not be made for Wyoming underground operations. In addition, Bridger coal is mined from GRB and requires a higher heat content than PRB coal, which also affects any straight cost comparison.

Because PRB coal is the next logical coal supply for Bridger, associated transportation costs to transport PRB coal to Bridger could possibly make this option economically infeasible. With that said, the affiliated interest statute allows for a review of costs that go into rates.

As a result, rate case staff should examine 2008 comparable coal costs to determine if the 2008 Bridger costs are in the range of 2008 comparable underground mining costs for the GRB region. If Bridger costs show a trend of exceeding comparable market costs, staff may be required to review the transfer pricing in UI 189 concerning Bridger in order to protect the public's interest.

In addition, during a rate case or TAM review, utility staff should recommend that Bridger coal costs be adjusted for the lower of cost or market for ratemaking. Again, the affiliated interest order concerning Bridger (Commission Order No. 01-472, UI 189) includes a condition that states:

> The Commission reserves the right to review for reasonableness all financial aspects of this arrangement in any rate proceeding or alternative form of regulation.

<u>*Staff Recommendations:*</u>

10. Staff should examine 2008 comparable coal costs to determine if the 2008 Bridger costs are in the range of 2008 comparable underground mining costs for the Green River Basin region. If Bridger costs show a trend of exceeding comparable market costs, staff may be required to review the transfer pricing in UI 189 concerning Bridger in order to protect the public's interest. *(Further investigation during the rate case)*

11. In future filings, Staff should recommend that Bridger coal costs be adjusted for the lower of cost or market for ratemaking. *(Further investigation during the rate case)*

Review of Affiliate Coal Costs

Staff examined account line detail of affiliate coal costs. The following comments are relevant concerning PacifiCorp's coal costs included in rates.

Bridger Coal

<u>Management/Supervisory Overtime</u>
Bridger experienced a significant increase in Management/Supervisory overtime costs from $117,838 in 2006 to an annualized amount of $448,908 in 2008. Audit Staff is not aware of any recent rate orders that have allowed overtime for management/supervisory personnel. The Oregon-allocated amount equals approximately $80,499 ($448,908 x 66.67 percent x .268974 allocation). As a

result of supervisory overtime costs, in future rate filings, assigned Staff should examine mining wage/salaries in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs

Bargaining/Temporary Overtime
Bridger experienced a significant increase in Bargaining/Temporary overtime costs from $6,866,573 in 2006 to an annualized amount of $10,537,424 in 2008 (57.3 percent). This 2008 overtime amount represented approximately 31 percent of Bargaining/ Temporary 2008 annualized total (regular plus overtime) pay. Bridger shifted from surface to combination underground/surface mining operation. As a result, Bridger increased full-time equivalents (FTE) from 288 to 353.

The following table examines FTE and regular/overtime wages for Bargaining/Temporary employees.

Table 29 – Bridger Bargaining/Temporary FTE and Wages (2008 Annualized)

		Per Employee
Total FTE	353	
Total Regular	$16,878,441	$47,814
Total Overtime	$10,537,424	$29,851
Total	**$27,416,218**	**$77,665**

As a result of the high overtime costs, in future rate filings, assigned Staff should examine mining wage/salaries in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Incentives
Bridger's 2008 annualized incentive costs equal approximately $878,067. Following the same methodology for ratemaking, Staff would recommend a 50 percent adjustment to incentives. The Oregon-allocated amount equals approximately $78,730 ($878,067/2 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine incentives in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Health Care Costs
According to PacifiCorp, Bridger Coal health care benefit programs target a 90/10 sharing arrangement for bargaining employees and programs ranging from a 90/10 to 74/26 for management employees. In the most recent energy utility rate case (UE 197), Staff recommended an 85/15 sharing of premium costs. Bridger's 2008 annualized health costs were $4,417,512. At an 85/15 sharing, these costs would be approximately $4,172,095. The Oregon-allocated amount

equals approximately $44,009 ($245,417 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine health care costs in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Employee - Meals

Bridger experienced $43,564 (annualized to $58,085) in meals and entertainment expenses. During a rate case, Staff will normally recommend a 50 percent sharing between customers and shareholders. This is a fair approach that somewhat mirrors the policy associated with bonuses (50 percent sharing between customers and shareholders) and the handling of these expenses for income tax purposes. For income tax purposes, the amount allowable as a federal income tax deduction for business meal and entertainment is generally limited to 50 percent of the total expense. The Oregon-allocated amount equals approximately $5,208 ($58,085/2 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine meals in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Donations

Bridger's 2008 annualized costs for donations are approximately $2,933. These costs should be disallowed because the Commission has not allowed regulated utilities to recover contributions to charities, community affairs, and economic development organizations through rates charged for regulated services. These expenses are discretionary and are not required to provide safe and adequate service to customers. In addition, Commission policy does not require customers to support causes in which they do not believe.[10] The Oregon-allocated amount equals approximately $526 ($2,933 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine donations in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Fines and Citations

Bridger's 2008 annualized costs for fines and citations are $203,388. Customers should not be required to pay for fines and citations incurred by Bridger. The Oregon-allocated amount equals approximately $36,473 ($203,388 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine fines and citations in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

[10] OPUC Order 87-406 states at pp. 40-41, "Since community affairs expenditures are discretionary, the funds could be retained by the business's owners. . . .Owners of unregulated businesses, rather than their customers, make community affairs contributions." Also see Order 91-186 at 16.

Other O&M
Because of the change in operations, Bridger experienced increased costs in many O&M line items and incurred other costs not experienced during surface mining operations. Audit Staff recommends that during future rate filings, Staff should examine line item costs in order to trend costs and to highlight any possible extraordinary costs that should not be included in rates.

Staff Recommendations concerning Bridger costs:

12. In future rate filings, assigned Staff should examine mining wage/salaries, overtime costs, health care costs, incentive, donations, meals and entertainment, and fines in the same method as Company wages are analyzed during rate cases and make the appropriate adjustments to coal costs.

13. In future rate filings, assigned Staff should examine line item costs in order to trend costs and to highlight any possible extraordinary costs.

Deer Creek Mine

Staff examined account-line detail for the Deer Creek Operations. The following comments are relevant concerning PacifiCorp's coal costs in rates.

Management/Supervisory Overtime
Deer Creek experienced a significant decrease in Management/Supervisory overtime costs from $351,306 in 2006 to an annualized amount of $182,525 in 2008. Although this is a decrease in costs, Audit Staff is not aware of any recent rate orders that have allowed overtime for management/supervisory personnel. The Oregon-allocated amount equals approximately $49,094 ($182,525 x .268974 allocation). In future rate filings, assigned Staff should examine supervisory overtime in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Bargaining Overtime
Deer Creek experienced a increase in bargaining overtime costs from $2,350,962 in 2006 to an annualized amount of $2,526,102 in 2008. This 2008 overtime amount represented approximately 18.4 percent of Bargaining 2008 annualized total (regular plus overtime) pay. The following table examines FTE and regular/overtime wages for bargaining employees.

Table 30 – Deer Creek Bargaining FTE and Wages (2008 Annualized)

		Per Employee
Total FTE	278	
Total Regular	$11,217,881	$40,352
Total Overtime	$2,526,102	$9,087
Total	**$13,744,261**	**$49,439**

As can be seen from the above table, total pay of Deer Creek bargaining personnel ($49,439) is approximately 63.7 percent of total average bargaining pay of Bridger Coal ($77,655). This difference is primarily a result of lower overtime payments and reflects a considerable savings for ratepayers. In future rate filings, assigned Staff should examine mining wage/salaries in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Incentives

Deer Creek's 2008 annualized incentive costs equal approximately $1,230,000. Following the same methodology for ratemaking, Staff would recommend a 50 percent adjustment to incentives. The Oregon-allocated amount equals approximately $165,419 ($1,230,000/2 x .268974 allocation). In future rate filings, assigned Staff should examine incentives in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Health Care Costs

According to PacifiCorp, Deer Creek's health care benefit programs in 2007 and 2008 ranged from 85/15 to 80/20 cost sharing. The option of a 90/10 cost sharing arrangement for management employees was implemented in 2008. All other plans have a 74/26 cost sharing arrangement in 2008. In the most recent energy utility rate case (UE 197), Staff recommended an 85/15 sharing of premium costs. In future rate filings, assigned Staff should examine health care costs in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Meals and Entertainment

Deer Creek experienced $33,463 (annualized to $44,617) in meals and entertainment expenses. As previously mentioned, during a rate case, Staff will normally recommend a 50 percent sharing between customers and shareholders. The Oregon-allocated amount equals approximately $6,000 ($44,617/2 x .268974 allocation). In future rate filings, assigned Staff should examine meals in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Club/Organization Membership and Expense

Although Deer Creek had costs in 2006 and 2007 for this line item, PacifiCorp reported $0 for 2008. Normally, this is a cost item that staff would examine in more detail; however because there is no cost in 2008, a further review is not necessary. In future rate filings, assigned Staff should examine membership expenses in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Mining Services

In 2008, Deer Creek Mine experienced $2.33 million in mining services. According to PacifiCorp, these services are for major equipment overhauls performed away from the mine at vendor facilities. During PacifiCorp's subsequent rate filings these costs should be reviewed in detail to determine if some of these expenses are more correctly capitalized. This is because replacements and overhauls generally have the effect of increasing the service potential of an asset by either improving the asset's efficiency or extending the asset's economic useful life. As a result, the costs of replacements and overhauls are capitalized.[11]

Other O&M

Audit Staff recommends that during future rate filings, assigned staff should examine line item costs in order to trend costs and to highlight any possible extraordinary costs. Concerning Deer Creek, Audit Staff notes considerable increase in professional services, management fees, royalties, and fuel from 2007 to 2008.

Staff Recommendations concerning Deer Creek costs:

14. In future rate filings, assigned Staff should examine mining wage/salaries, overtime costs, health care costs, incentive, donations, meals and entertainment, and membership expenses in the same method as Company wages are analyzed during rate cases and make the appropriate adjustments to coal costs.

15. In future rate filings, assigned Staff should examine line item costs in order to trend costs and to highlight any possible extraordinary costs.

Trapper Mining

Because PacifiCorp is a minority owner of Trapper Mining, PacifiCorp did not have detailed line item costs for Trapper Mining. However, as previously mentioned, Trapper Mining costs were lower than the listed DOE/EIA 2007 market costs. As a result, PacifiCorp is actually receiving goods at the lower of cost or market.

Coal Transportation

PacifiCorp's Cholla, Dave Johnston, and Hayden Plant all received transported coal. The following table examines transportation cost per ton.

[11] Munter – Radcliffe, *Applying GAAP and GAAS, Depreciable and Intangible Assets*, Matthew Bender & Co., Inc. page 10-21.

Table 31 - Coal Transportation Costs

Plant	2006	2007	2008	Percent Change 2007 - 2008
Cholla – Arizona (Coal from New Mexico and Montana	$4.91*	$7.47	$7.97	6.69%
Dave Johnston – Wyoming (Coal from Wyoming)	$4.65	$4.68	$4.94	5.26%
Hayden – Colorado (Coal from Colorado)	NA**	NA	$2.76	NA

** Cholla's 2006 costs were significantly lower than subsequent years due to a $3 million credit applied to Cholla in January 2006.*

*** Prior to 2008, PacifiCorp did not separate transportation costs from coal costs at the Hayden plant.*

Because PacifiCorp's Cholla plant is located in Arizona, higher transportation costs would be reasonably expected. Because of the low cost of coal being supplied to the Dave Johnston plant ($7.14 in 2008), transportation costs actually account for approximately 40.4 percent of total coal costs. Even with transportation costs, the Dave Johnston plant had the second lowest 2008 coal costs for PacifiCorp plants at $12.07 per ton. Only the Wyodak plant, supplied by the Wyodak mine and not requiring transportation, had lower costs at $11.49 per ton.

As previously mentioned, PacifiCorp has two Commission approved affiliated contracts with Burlington Northern Santé Fe Railroad (BNSF). Berkshire-Hathaway currently owns 17 percent of BNSF. PacifiCorp has long-term coal transportation contracts with BNSF, including indirect payments to a generation plant that is jointly owned by PacifiCorp. The transportation contacts were approved by the Commission in Order No. 07-323 (UI 269), dated July 27, 2007. BNSF provides transportation services from:

1. Various coal mines in the Wyoming Powder River Basin to PacifiCorp's David Johnston Steam Plant (David Johnston); and

2. Various coal mines in Wyoming, New Mexico, and Montana to PacifiCorp's Cholla Generating Station (Cholla).

These agreements were executed as third-party agreements prior to PacifiCorp becoming a subsidiary of MEHC. This type of service is provided pursuant to a contract filed and approved by the Surface Transportation Board (STB)[12] would generally not require Commission approval; however, PacifiCorp and MEHC agreed to a different affiliate transaction standard as part of PacifiCorp's acquisition by MEHC. PacifiCorp pays approximately $30 million per year for services under the Agreements with BNSF. PacifiCorp records most of the charges related to the BNSF agreements in FERC Account 501, Fuel.

Operations and Maintenance Expenses

The following table presents O&M expenses (FERC accounts 500-598) for 2006 and 2007:

Table 32 - O&M Cost Comparison

	2006	2007	Percentage Change 2006-2007
Labor	123,864,786	100,446,457	-18.9%
Non-Labor	432,179,061	572,124,600	32.4%
Total O&M	556,043,847	672,571,057	21.0%

The overall increase is higher than the Consumers Price Index for All Urban Consumers of 2.8 percent for the period and is largely attributable to two areas – (1) higher gas costs and (2) plant additions. An account comparison was made and there were 15 instances of year-to-year variances greater than 10 percent. The company provided satisfactory explanations for these increases. The distortions due to singular accounting occurrences i.e. out-of-period charges were also itemized.

Customer Service

The company stated that there is a ten-year technology improvement plan. There are four current deliverables:

1. Customer correspondence improvement project – template improvement as to location and clarity.
2. Automated outage customer call back program – customizing notification and follow up service restoration.
3. Computer telephony integration and interactive voice response systems – symmetry between account information displayed online and phone accessible and multiple phone match screens.

[12] The Surface Transportation Board (STB) was created in the Interstate Commerce Commission Termination Act of 1995 and is the successor agency to the Interstate Commerce Commission. The STB is an economic regulatory agency that Congress charged with the fundamental missions of resolving railroad rate and service disputes and reviewing proposed railroad mergers. The STB is decisionally independent, although it is administratively affiliated with the Department of Transportation. (www.stb.dot.gov)

Docket No. UE 307
Exhibit PAC/602
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of R. Bryce Dalley

Staff's Discovery Response from docket UE 264

August 2016

Data Request No. 2:

2. Is Staff's position that the Commission should review the ongoing prudence of the Company's coal supply from its affiliate mines on a long-term (*i.e.*, multiple-year) basis, rather than on a year-by-year basis as coal supply costs fluctuate in annual NPC updates? Does Staff support PacifiCorp preparing a long-term fuel plan for its affiliate mines to facilitate such a review?

Response to Data Request No. 2:

2. It is Staff's position that PacifiCorp can simultaneously satisfy the Commission's prudence standard and affiliate transaction standard (i.e., OAR 860-027-0048) by comparing its affiliate mine fuel plan to other alternative fuel plans, including market alternatives, which are known to be available at the times when the Company is deciding whether to continue or extend operations at the affiliate mines. Market alternatives could include reliance on short-term single-year coal contracts or long-term multiple-year coal contracts.

   If a multi-year cost-based affiliate mine fuel plan is the most reasonable plan when compared to other alternatives, including the market alternatives, then the affiliate mine fuel plan would likely satisfy both the Commission's prudence standard and affiliate transaction "lower of cost or market" standard in a future rate proceeding or proceedings. In other words, the "market" in the "lower of cost or market" standard should be the most reasonable market alternative that was available to the company at the time it made its decision to continue or extend operations at the affiliate mines.

   Staff does not support the concept that the prudence standard or the affiliate transaction standard should only be applied once at the time the decisions to open the mine or create the affiliate are first made. Staff supports ongoing application of these standards.

   Staff also does not support a definition of the "market" comparator in the "lower of cost or market" standard that introduces hindsight into the test. Staff supports definitions of "market" that align with the market alternatives that were known, or should have been known, to be available at the times when the Company was deciding whether to continue or extend operations at the affiliate mines.

   Staff supports PacifiCorp periodically (e.g., no less than once every three years) preparing a fuel supply plan that compares affiliate mine fuel supply to other alternative fuel supply options, including market alternatives, to facilitate the implementation of the Commission's prudence and affiliate transaction standards in future rate proceedings.

Docket No. UE 307
Exhibit PAC/603
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of R. Bryce Dalley

Staff's Response to PacifiCorp Data Requests 6-10

August 2016

UE 307/OPUC
July 19, 2016
PacifiCorp 1st Set of Data Requests

PacifiCorp Data Request 6

Refer to Staff/100, Crider/21, lines 11-16. Please quantify the impact (on a total company and Oregon basis) of Staff's recommended treatment of production tax credits in this case, including the total level of production tax credits that Staff is proposing to include in customer rates. Please provide all workpapers used to calculate Staff's proposed adjustment.

Response to PacifiCorp Data Request 6

On a total company basis, Staff recommends removing approximately $65.8 million of PTC credits from base rates and including approximately $54.4 million in PTC credits in the CY 2017 projected net power costs, as shown in testimony Exhibit PAC/106, Dickman/2.

Staff has generated no workpapers.

UE 307/OPUC
July 19, 2016
PacifiCorp 1st Set of Data Requests

PacifiCorp Data Request 7

Refer to Staff/100, Crider/21, lines 1-9. Is it Staff's proposal in this docket to apply the same treatment with respect to production tax credits as proposed by Portland General Electric (PGE) in the 2017 Annual Power Cost Update Tariff, docket UE 308? If yes, please provide the references to documents relied on to develop Staff's proposal.

Response to PacifiCorp Data Request 7

Yes. Please refer to Docket UE 308, specifically (UE308) PGE/400, Niman-Peschka-Hager/28 at 6-18, reproduced below for convenience:

Q. Other than the components included in its NVPC forecast, will PGE make any other changes to account for the price impacts of its 2017 PTC forecast?

A. Yes. We will re-categorize the fixed and variable components of the generation revenue requirement approved by Commission Order No. 15-356 in Docket No. UE 294. There will be no net change in the generation revenue requirement, but we will remove the credit from fixed costs and apply the credit to variable costs. This re-categorization will increase fixed costs but variable costs will decrease by the same amount.

Q. What effect does the forecast of federal production tax credits have on the variable cost portion of PGE's generation revenue requirement?

A. Table 3 shows the change in generation revenue requirement, which is the result of price and quantity changes from 2016 to 2017. The variable cost portion of PGE's generation revenue requirement increases by $5.3 million in 2017 (i.e., PTC benefit decreases from $81.5 million to $76.2 million).

Table 3
Change in Generation Revenue Requirement due to PTCs

	2016	2017
PTC	$24/MWh	$23/MWh
Quantity	2,047,929 MWh	1,999,245 MWh
Gross-Up Factor	1.658	1.658
Generation Revenue Requirement	($81.5 million)	($76.2 million)

UE 307/OPUC
July 19, 2016
PacifiCorp 1st Set of Data Requests

PacifiCorp Data Request 8

Refer to Staff/100, Crider/19, lines 22-24. Please explain how Staff's proposal with respect to production tax credits addresses the "approximately $3.5 million of credit surplus... included in base rates for 2017...."

Response to PacifiCorp Data Request 8

Staff's proposal removes all PTC credits from base rates and includes the CY 2017 projection of PTC credits entirely in net power costs. The removal of PTCs from base rates will address the $3.5 million credit surplus by removing these from base rates.

UE 307/OPUC
July 19, 2016
PacifiCorp 1st Set of Data Requests

PacifiCorp Data Request 9

Refer to Staff/100, Crider/21, lines 1-9. Does Staff agree that if a full forecast of production tax credits is included in the transition adjustment mechanism, an offset in base rates is necessary to avoid double counting production tax credits reflected in customer rates? If no, please explain.

Response to PacifiCorp Data Request 9

Yes, Staff agrees with the premise stated in the question.

UE 307/OPUC
July 19, 2016
PacifiCorp 1st Set of Data Requests

PacifiCorp Data Request 10

Is it Staff's position that it would be appropriate to allow the Company to modify its base rates in this proceeding to accommodate Staff's recommendation that the full value of forecast production tax credits be reflected in the 2017 transition adjustment mechanism?

Response to PacifiCorp Data Request 10

Yes, the question correctly states Staff's position.

Docket No. UE 307
Exhibit PAC/604
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of R. Bryce Dalley

Production Tax Credit details

August 2016

PacifiCorp
CY 2017 TAM
Production Tax Credits - Stand Alone TAM Adjustment

Line no	Plant Name	PTC Expiration Date	Total Company	Factor	Factors CY	Oregon Allocated	Oregon Allocated
	PTC Revenue Requirement in UE-263						
	Plant Name	PTC Expiration Date	UE-263 Final	Factor	Factors CY 2014	UE-263 Final[1]	Revenue Requirement
1	JC Boyle	11/7/2015	$ (103,599)	SG	26.053%	$ (26,991)	$ (43,442)
2	Blundell Bottoming Cycle KWh	12/1/2017	(1,896,326)	SG	26.053%	(494,050)	(795,177)
3	Glenrock KWh	12/30/2018	(7,646,838)	SG	26.053%	(1,992,231)	(3,206,513)
4	Glenrock III KWh	1/16/2019	(2,861,406)	SG	26.053%	(745,482)	(1,199,860)
5	Goodnoe KWh	12/17/2017	(6,138,401)	SG	26.053%	(1,599,238)	(2,573,987)
6	High Plains Wind	10/14/2019	(7,115,510)	SG	26.053%	(1,853,804)	(2,983,713)
7	Leaning Juniper 1 KWh	9/13/2016	(7,025,884)	SG	26.053%	(1,830,454)	(2,946,131)
8	Marengo KWh	8/2/2017	(9,042,126)	SG	26.053%	(2,355,745)	(3,791,592)
9	Marengo II KWh	6/25/2018	(4,306,194)	SG	26.053%	(1,121,893)	(1,805,696)
10	McFadden Ridge	10/31/2019	(1,979,446)	SG	26.053%	(515,705)	(830,032)
11	Seven Mile KWh	12/30/2018	(8,040,700)	SG	26.053%	(2,094,844)	(3,371,669)
12	Seven Mile II KWh	12/30/2018	(1,583,828)	SG	26.053%	(412,635)	(664,139)
13	Dunlap I Wind KWh	9/29/2020	(8,132,932)	SG	26.053%	(2,118,873)	(3,410,344)
14							
15	Total Production Tax Credit		$ (65,873,190)			$ (17,161,943)	$ (27,622,295)
16							
17						$ Change due to load variance from UE-263 forecast[2]	$ 536,921
18						CY 2017 PTC in Rates	$ (27,085,374)
19							
20							
21	**PTC Revenue Requirement CY 2017**						
22			**Total Company**			**Oregon Allocated**	
23	Plant Name	PTC Expiration Date	CY 2017	Factor	Factors CY 2017	CY 2017[3]	Revenue Requirement
24	JC Boyle	11/7/2015	-	SG	25.230%	-	-
25	Blundell Bottoming Cycle KWh	12/1/2017	(1,642,252)	SG	25.230%	(414,346)	(666,893)
26	Glenrock KWh	12/30/2018	(7,453,247)	SG	25.230%	(1,880,479)	(3,026,648)
27	Glenrock III KWh	1/16/2019	(2,785,143)	SG	25.230%	(702,701)	(1,131,003)
28	Goodnoe KWh	12/17/2017	(5,991,082)	SG	25.230%	(1,511,570)	(2,432,885)
29	High Plains Wind	10/14/2019	(7,115,510)	SG	25.230%	(1,795,267)	(2,889,498)
30	Leaning Juniper 1 KWh	9/13/2016	-	SG	25.230%	-	-
31	Marengo KWh	8/2/2017	(5,447,249)	SG	25.230%	(1,374,359)	(2,212,043)
32	Marengo II KWh	6/25/2018	(4,306,194)	SG	25.230%	(1,086,467)	(1,748,678)
33	McFadden Ridge	10/31/2019	(1,979,446)	SG	25.230%	(499,421)	(803,822)
34	Seven Mile KWh	12/30/2018	(7,996,481)	SG	25.230%	(2,017,539)	(3,247,246)
35	Seven Mile II KWh	12/30/2018	(1,575,118)	SG	25.230%	(397,408)	(639,631)
36	Dunlap I Wind KWh	9/29/2020	(8,132,932)	SG	25.230%	(2,051,966)	(3,302,657)
37							
38	Total Production Tax Credit		(54,424,654)			(13,731,523)	(22,101,005)
39							
40						Increase Absent Load Change	5,521,291
41						**Increase Including Load Change**	**4,984,369**

Notes:
[1] See PAC/400, Dickman/106.
[2] Precise adjustment based on rates developed for reply proposal. Differs from estimated load variance amount in filed case of $546,184 by $9,263.
[3] See PAC/400, Dickman/106.

Docket No. UE 307
Exhibit PAC/700
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Judith M. Ridenour

August 2016

REPLY TESTIMONY OF JUDITH M. RIDENOUR

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ATTACHED EXHIBITS

Exhibit PAC/701—Proposed Adjustment to Schedule 200, Base Supply Service

Exhibit PAC/702—Proposed Reply TAM Rate Spread and Rates

Exhibit PAC/703—Proposed Reply TAM Adjustment for Other Items

Exhibit PAC/704—Proposed Reply Tariff Schedules

Exhibit PAC/705—Estimated Effect of Proposed Reply TAM Price Change

Q. Are you the same Judith M. Ridenour who testified previously for PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) in this docket?

A. Yes.

PURPOSE OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. I present the Company's revised proposed rates and revised tariff pages reflecting the Company's reply position. I demonstrate how the Company will implement the change discussed by Company witness Mr. R. Bryce Dalley, accepting Staff's approach to updating Production Tax Credits (PTCs) in the Transition Adjustment Mechanism (TAM). I also provide an updated summary of the impact of the proposed rate change on customers' bills.

PRODUCTION TAX CREDITS IN RATES

Q. How are PTCs currently collected in the Company's rates?

A. PTCs are currently collected as part of fixed generation costs through Schedule 200, Base Supply Service. The rates in Schedule 200 were set in the Company's last general rate case, docket UE 263.

Q. Please describe the Company's reply position on PTCs, responding to Staff's recommended approach to updating PTCs in the TAM.

A. The Company now proposes to adjust Schedule 200 rates to completely remove PTCs and then include the 2017 PTC revenue requirement with net power costs to be collected through Schedule 201, Net Power Costs – Cost-Based Supply Service. Going forward, this will allow PTCs to be easily updated in future TAM filings.

Q. How does the Company propose to remove PTCs from Schedule 200?

A. The Company proposes to remove PTCs from Schedule 200 based on the allocation of fixed generation costs in Schedule 200 from the last general rate case, docket UE 263. Using the test period where the rates were set to make this adjustment ensures that the revenues are properly removed on the same basis as they were set.

Q. Did you prepare an exhibit showing the proposed rate adjustments to be made to Schedule 200?

A. Yes. Exhibit PAC/701 shows present Schedule 200 rates and revenues as approved based on the docket UE 263 test period, twelve months ending December 2014. This rate spread is then used to allocate the removal of the $27.6 million in PTC revenue requirement credit included in rates, as identified by Mr. Dalley in his reply testimony. Per kilowatt and per kilowatt-hour adjustments have been calculated for each rate and added to the present Schedule 200 rates to arrive at the proposed Schedule 200 rates in the far right column. These proposed Schedule 200 rates represent the portion of Schedule 200 rates approved in docket UE 263 to collect the remainder of fixed generation costs.

Q. How does the Company propose to include the 2017 PTC revenue requirement credit in rates?

A. The Company proposes to add the 2017 PTC revenue requirement credit of $22.1 million to the TAM revenue requirement as presented by Company witness Mr. Brian Dickman in his reply testimony. The total revenue requirement will then be collected through Schedule 201. The total TAM Schedule 201 revenue requirement of $354 million is presented by Mr. Dickman in his reply Exhibit PAC/401.

Q. Did you prepare an exhibit showing the revised proposed Schedule 201 rates?

A. Yes. Exhibit PAC/702 shows the revised proposed Schedule 201 rates which reflect the TAM reply revenue requirement including PTCs.

Q. Are there any other rate changes related to the Company's reply proposal regarding PTCs?

A. Yes. In its Initial Filing, the Company included the change in PTCs as part of Schedule 205, TAM Adjustment for Other Items. Exhibit PAC/703 shows the updated proposed adjustments to Schedule 205 rates and revenues based on the reply amounts for this adjustment. The additional adjustment related to PTCs is no longer included. Similar to the filed exhibit for Schedule 205, the last column shows the total combined Schedule 205 rates for the tariff, which reflect the present Schedule 205 rates plus the reply adjustment for the 2017 TAM.

Q. Please describe Exhibit PAC/704.

A. Exhibit PAC/704 contains the proposed revised Schedules 200, 201 and 205 reflecting the revised rates presented above.

COMPARISON OF PRESENT AND PROPOSED CUSTOMER RATES

Q. Does the Company's revised treatment of PTCs in rates affect the overall or class rate impacts in this case?

A. No. The Company's revised PTC treatment results in the same overall and class impacts as the Company's original proposal. The changes in class rate impacts presented below are related to the other adjustments to net power costs presented in the Company's reply case.

Q. What are the overall rate effects of the changes proposed in this reply filing?

A. The overall proposed effect is a rate increase of 1.3 percent on a net basis. The rate change varies by customer type. Page one of Exhibit PAC/705 shows the estimated effect of the Company's proposed prices by delivery service schedule both excluding (base) and including (net) applicable adjustment schedules. Exhibit PAC/705 is an updated version of Exhibit PAC/304.

Q. Does Exhibit PAC/705 include updated customer bill impacts as a result of the proposed changes to Schedule 200, Schedule 201 and Schedule 205?

A. Yes. Exhibit PAC/705, beginning on page 2, contains monthly billing comparisons for customers at different usage levels served on each of the major delivery service schedules. Each bill impact is shown in both dollars and percentages. These bill comparisons include the effects of all adjustment schedules.

Q. What is the estimated monthly impact to an average residential customer?

A. The estimated monthly impact to the average residential customer using 900 kilowatt-hours per month is a bill increase of $1.09.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 307
Exhibit PAC/701
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Judith M. Ridenour

Proposed Adjustment to Schedule 200, Base Supply Service

August 2016

PACIFIC POWER
STATE OF OREGON
TAM Adjustment to Schedule 200 to remove Production Tax Credits
Present and Proposed Rates and Revenues
UE 263 Test Period - Forecast 12 Months Ending December 31, 2014

Rate Schedule	UE 263 Forecast Energy	Schedule 200 Rates	Schedule 200 Revenues	Rate Spread	Target Revenues	Proposed Adj to Rem PTC Rates	Proposed Adj to Rem PTC Revenues	Proposed Schedule 200 Rates
Schedule 4, Residential								
First Block kWh (0-1,000)	3,976,721,700	2 729 ¢	$108,524,735	28 7438%	$7,857,896	0 198 ¢	$7,873,909	2 927 ¢
Second Block kWh (> 1,000)	1,402,846,969	3 726 ¢	$52,270,078	13 8442%	$3,784,693	0 270 ¢	$3,787,687	3 996 ¢
	5,379,568,669		$160,794,813		$11,642,589		$11,661,596	
Employee Discount								
First Block kWh (0-1,000)	11,494,539	2 729 ¢	$313,686			0 198 ¢	$22,759	2 927 ¢
Second Block kWh (> 1,000)	5,411,252	3 726 ¢	$201,623			0 270 ¢	$14,610	3 996 ¢
	16,905,791		$515,309				$37,369	
Discount			-$128,827				-$9,342	
Schedule 23, Small General Service								
Secondary Voltage								
1st 3,000 kWh, per kWh	854,629,409	3 138 ¢	$26,818,271	7 1031%	$1,941,817	0 227 ¢	$1,940,009	3 365 ¢
All additional kWh, per kWh	245,180,628	2 329 ¢	$5,710,257	1 5124%	$413,460	0 169 ¢	$414,355	2 498 ¢
	1,099,810,037		$32,528,528		$2,355,277		$2,354,364	
Primary Voltage								
1st 3,000 kWh, per kWh	792,413	3 050 ¢	$24,169	0 0064%	$1,750	0 221 ¢	$1,751	3 271 ¢
All additional kWh, per kWh	354,704	2 263 ¢	$8,027	0 0021%	$581	0 164 ¢	$582	2 427 ¢
	1,147,117		$32,196		$2,331		$2,333	
Schedule 28, General Service 31-200kW								
Secondary Voltage								
1st 20,000 kWh, per kWh	1,402,035,556	3 081 ¢	$43,196,715	11 4411%	$3,127,723	0 223 ¢	$3,126,539	3 304 ¢
All additional kWh, per kWh	572,241,543	2 999 ¢	$17,161,524	4 5454%	$1,242,606	0 217 ¢	$1,241,764	3 216 ¢
	1,974,277,099		$60,358,239		$4,370,329		$4,368,303	
Primary Voltage								
1st 20,000 kWh, per kWh	9,746,389	2 898 ¢	$282,450	0 0748%	$20,451	0 210 ¢	$20,467	3 108 ¢
All additional kWh, per kWh	8,827,384	2 820 ¢	$248,932	0 0659%	$18,024	0 204 ¢	$18,008	3 024 ¢
	18,573,773		$531,382		$38,476		$38,475	
Schedule 30, General Service 201-999kW								
Secondary Voltage								
Demand Charge, per kW	3,417,800	$1 75	$5,981,150	1 5842%	$433,074	$0 13	$434,061	$1 88
1st 20,000 kWh, per kWh	180,025,326	2 667 ¢	$4,801,275	1 2717%	$347,644	0 193 ¢	$347,449	2 860 ¢
All additional kWh, per kWh	1,066,138,835	2 313 ¢	$24,659,791	6 5314%	$1,785,529	0 167 ¢	$1,780,452	2 480 ¢
	1,246,164,161		$35,442,216		$2,566,247		$2,561,962	
Primary Voltage								
Demand Charge, per kW	264,892	$1 75	$463,561	0 1228%	$33,565	$0 13	$33,641	$1 88
1st 20,000 kWh, per kWh	12,257,555	2 601 ¢	$318,819	0 0844%	$23,085	0 188 ¢	$23,044	2 789 ¢
All additional kWh, per kWh	79,340,490	2 248 ¢	$1,783,574	0 4724%	$129,142	0 163 ¢	$129,325	2 411 ¢
	91,598,045		$2,565,954		$185,792		$186,010	
Schedule 41, Agricultural Pumping Service								
Secondary Voltage								
Winter, 1st 100 kWh/kW, per kWh	2,861,725	4 316 ¢	$123,512	0 0327%	$8,943	0 313 ¢	$8,957	4 629 ¢
Winter, All additional kWh, per kWh	2,445,439	2 942 ¢	$71,945	0 0191%	$5,209	0 214 ¢	$5,233	3 156 ¢
Summer, All kWh, per kWh	225,681,647	2 942 ¢	$6,639,554	1 7586%	$480,747	0 214 ¢	$482,959	3 156 ¢
	230,988,811		$6,835,011		$494,899		$497,149	
Primary Voltage								
Winter, 1st 100 kWh/kW, per kWh	9,811	4 194 ¢	$411	0 0001%	$30	0 303 ¢	$30	4 497 ¢
Winter, All additional kWh, per kWh	56,114	2 859 ¢	$1,604	0 0004%	$116	0 207 ¢	$116	3 066 ¢
Summer, All kWh, per kWh	348,776	2 859 ¢	$9,972	0 0026%	$722	0 207 ¢	$722	3 066 ¢
	414,701		$11,987		$868		$868	
Schedule 47, Large General Service, Partial Requirements 1,000kW and over								
Primary Voltage								
Demand Charge, per kW	405,068	$1 74	$704,818			$0 13	$51,039	$1 87
On-Peak, per on-peak kWh	84,413,283	2 280 ¢	$1,924,623			0 163 ¢	$137,594	2 443 ¢
Off-Peak, per off-peak kWh	39,529,056	2 230 ¢	$881,498			0 163 ¢	$64,432	2 393 ¢
	123,942,339		$3,510,939		$253,065		$253,065	
Transmission Voltage								
Demand Charge, per kW	92,839	$1 75	$162,468			$0 13	$11,791	$1 88
On-Peak, per on-peak kWh	10,531,685	2 196 ¢	$231,276			0 157 ¢	$16,535	2 353 ¢
Off-Peak, per off-peak kWh	8,003,363	2 146 ¢	$171,752			0 157 ¢	$12,565	2 303 ¢
	18,535,048		$565,496		$40,891		$40,891	

PACIFIC POWER
STATE OF OREGON
TAM Adjustment to Schedule 200 to remove Production Tax Credits
Present and Proposed Rates and Revenues
UE 263 Test Period - Forecast 12 Months Ending December 31, 2014

	UE 263	Schedule 200		Rate	Target	Proposed Adj to Rem PTC		Proposed Schedule 200
Rate Schedule	Forecast Energy	Rates	Revenues	Spread	Revenues	Rates	Revenues	Rates
Schedule 48, Large General Service, 1,000kW and over								
Secondary Voltage								
Demand Charge, per kW	1,536,500	$1 71	$2,627,415	0 6959%	$190,242	$0 12	$190,526	$1 83
On-Peak, per on-peak kWh	370,279,657	2 408 ¢	$8,916,334	2 3616%	$645,601	0 173 ¢	$640,584	2 581 ¢
Off-Peak, per off-peak kWh	205,466,197	2 358 ¢	$4,844,893	1 2832%	$350,802	0 173 ¢	$355,457	2 531 ¢
	575,745,854		$16,388,642		$1,186,644		$1,186,567	
Primary Voltage								
Demand Charge, per kW	3,526,702	$1 74	$6,136,461	1 6253%	$444,320	$0 13	$444,364	$1 87
On-Peak, per on-peak kWh	943,087,671	2 280 ¢	$21,502,399	5 6951%	$1,556,913	0 163 ¢	$1,537,233	2 443 ¢
Off-Peak, per off-peak kWh	586,385,011	2 230 ¢	$13,076,386	3 4634%	$946,815	0 163 ¢	$955,808	2 393 ¢
	1,529,472,682		$40,715,246		$2,948,048		$2,937,405	
Transmission Voltage								
Demand Charge, per kW	1,285,292	$1 75	$2,249,261	0 5957%	$162,861	$0 13	$163,232	$1 88
On-Peak, per on-peak kWh	472,809,887	2 196 ¢	$10,382,905	2 7500%	$751,790	0 157 ¢	$742,312	2 353 ¢
Off-Peak, per off-peak kWh	357,086,194	2 146 ¢	$7,663,070	2 0296%	$554,856	0 157 ¢	$560,625	2 303 ¢
	829,896,081		$20,295,236		$1,469,507		$1,466,169	
Schedule 15, Outdoor Area Lighting Service								
Secondary Voltage								
All kWh, per kWh	9,286,499	2 117 ¢	$196,595	0 0521%	$14,235	0 153 ¢	$14,208	2 270 ¢
	9,286,499		$196,595		$14,235		$14,208	
Schedule 50, Mercury Vapor Street Lighting Service								
Secondary Voltage								
All kWh, per kWh	7,823,337	1 909 ¢	$149,348	0 0396%	$10,814	0 138 ¢	$10,796	2 047 ¢
	7,823,337		$149,348		$10,814		$10,796	
Schedule 51, Street Lighting Service, Company-Owned System								
Secondary Voltage								
All kWh, per kWh	19,612,310	3 015 ¢	$591,311	0 1566%	$42,815	0 218 ¢	$42,755	3 233 ¢
	19,612,310		$591,311		$42,815		$42,755	
Schedule 52, Street Lighting Service, Company-Owned System								
Secondary Voltage								
All kWh, per kWh	523,143	2 310 ¢	$12,085	0 0032%	$875	0 167 ¢	$874	2 477 ¢
	523,143		$12,085		$875		$874	
Schedule 53, Street Lighting Service, Consumer-Owned System								
Secondary Voltage								
All kWh, per kWh	8,966,764	0 986 ¢	$88,412	0 0234%	$6,402	0 071 ¢	$6,366	1 057 ¢
	8,966,764		$88,412		$6,402		$6,366	
Schedule 54, Recreational Field Lighting								
Secondary Voltage								
All kWh, per kWh	1,249,347	1 697 ¢	$21,201	0 0056%	$1,535	0 123 ¢	$1,537	1 820 ¢
	1,249,347		$21,201		$1,535		$1,537	
Total before Employee Discount			**$381,634,837**	100 0000%	$27,631,637		**$27,631,693**	
Employee Discount			-$128,827		-$9,342		-$9,342	
TOTAL	**13,167,595,817**		**$381,506,010**		$27,622,295		**$27,622,351**	

Schedule 47 Unscheduled kWh	1,374,749
Total Forecast kWH	13,168,970,566

Docket No. UE 307
Exhibit PAC/702
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Judith M. Ridenour

Proposed Reply TAM Rate Spread and Rates

August 2016

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Net Power Costs
Present and Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2017

		Present Schedule 201		Present Rate	Target	Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Spread	Revenues	Rates	Revenues
Schedule 4, Residential							
First Block kWh (0-1,000)	3,866,192,250	2.729 ¢	$105,508,387	29.0330%	$102,030,092	2.639 ¢	$102,028,813
Second Block kWh (> 1,000)	1,363,856,082	3.728 ¢	$50,844,555	13.9910%	$49,168,363	3.605 ¢	$49,167,012
	5,230,048,332		$156,352,942		$151,198,454		$151,195,825
						Change	-$5,157,117
Employee Discount							
First Block kWh (0-1,000)	11,175,059	2.729 ¢	$304,967			2.639 ¢	$294,910
Second Block kWh (> 1,000)	5,260,850	3.728 ¢	$196,124			3.605 ¢	$189,654
	16,435,909		$501,091				$484,564
Discount			-$125,273				-$121,141
						Change	$4,132
Schedule 23, Small General Service							
Secondary Voltage							
1st 3,000 kWh, per kWh	871,764,198	3.023 ¢	$26,353,432	7.2517%	$25,484,638	2.923 ¢	$25,481,668
All additional kWh, per kWh	234,196,016	2.242 ¢	$5,250,675	1.4448%	$5,077,576	2.168 ¢	$5,077,370
	1,105,960,214		$31,604,107		$30,562,214		$30,559,038
						Change	-$1,045,069
Primary Voltage							
1st 3,000 kWh, per kWh	738,519	2.928 ¢	$21,624	0.0060%	$20,911	2.831 ¢	$20,907
All additional kWh, per kWh	329,186	2.172 ¢	$7,150	0.0020%	$6,914	2.100 ¢	$6,913
	1,067,705		$28,774		$27,825		$27,820
						Change	-$954
Schedule 28, General Service 31-200kW							
Secondary Voltage							
1st 20,000 kWh, per kWh	1,427,143,857	2.956 ¢	$42,186,372	11.6085%	$40,795,614	2.859 ¢	$40,802,043
All additional kWh, per kWh	582,416,811	2.875 ¢	$16,744,483	4.6076%	$16,192,468	2.780 ¢	$16,191,187
	2,009,560,668		$58,930,855		$56,988,081		$56,993,230
						Change	-$1,937,625
Primary Voltage							
1st 20,000 kWh, per kWh	9,801,024	2.846 ¢	$278,937	0.0768%	$269,741	2.752 ¢	$269,724
All additional kWh, per kWh	8,837,541	2.770 ¢	$244,800	0.0674%	$236,730	2.679 ¢	$236,758
	18,638,565		$523,737		$506,471		$506,482
						Change	-$17,255
Schedule 30, General Service 201-999kW							
Secondary Voltage							
1st 20,000 kWh, per kWh	184,702,861	3.160 ¢	$5,836,610	1.6061%	$5,644,194	3.056 ¢	$5,644,519
All additional kWh, per kWh	1,086,874,572	2.740 ¢	$29,780,363	8.1947%	$28,798,594	2.650 ¢	$28,802,176
	1,271,577,433		$35,616,973		$34,442,788		$34,446,695
						Change	-$1,170,278
Primary Voltage							
1st 20,000 kWh, per kWh	12,525,631	3.125 ¢	$391,426	0.1077%	$378,522	3.022 ¢	$378,525
All additional kWh, per kWh	80,863,348	2.701 ¢	$2,184,119	0.6010%	$2,112,115	2.612 ¢	$2,112,151
	93,388,979		$2,575,545		$2,490,637		$2,490,676
						Change	-$84,869
Schedule 41, Agricultural Pumping Service							
Secondary Voltage							
Winter, 1st 100 kWh/kW, per kWh	2,915,053	4.221 ¢	$123,044	0.0339%	$118,988	4.082 ¢	$118,992
Winter, All additional kWh, per kWh	2,478,448	2.876 ¢	$71,280	0.0196%	$68,930	2.781 ¢	$68,926
Summer, All kWh, per kWh	227,452,860	2.876 ¢	$6,541,544	1.8001%	$6,325,889	2.781 ¢	$6,325,464
	232,846,361		$6,735,868		$6,513,807		$6,513,382
						Change	-$222,486
Primary Voltage							
Winter, 1st 100 kWh/kW, per kWh	10,164	4.086 ¢	$415	0.0001%	$401	3.948 ¢	$401
Winter, All additional kWh, per kWh	58,136	2.786 ¢	$1,620	0.0004%	$1,567	2.694 ¢	$1,566
Summer, All kWh, per kWh	361,344	2.786 ¢	$10,067	0.0028%	$9,735	2.694 ¢	$9,735
	429,644		$12,102		$11,703		$11,702
						Change	-$400
Schedule 47, Large General Service, Partial Requirements 1,000kW and over							
Primary Voltage							
On-Peak, per on-peak kWh	35,574,864	2.584 ¢	$919,254			2.499 ¢	$889,016
Off-Peak, per off-peak kWh	12,536,048	2.534 ¢	$317,663			2.449 ¢	$307,008
	48,110,912		$1,236,917		$1,196,024		$1,196,024
						Change	-$40,893
Transmission Voltage							
On-Peak, per on-peak kWh	49,897,565	2.427 ¢	$1,211,014			2.349 ¢	$1,172,094
Off-Peak, per off-peak kWh	41,971,311	2.377 ¢	$997,658			2.299 ¢	$964,920
	91,868,876		$2,208,672		$2,137,014		$2,137,014
						Change	-$71,658

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Net Power Costs
Present and Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2017

Rate Schedule	Forecast Energy	Present Schedule 201 Rates	Present Schedule 201 Revenues	Present Rate Spread	Target Revenues		Proposed Schedule 201 Rates	Proposed Schedule 201 Revenues
Schedule 48, Large General Service, 1,000kW and over								
Secondary Voltage								
On-Peak, per on-peak kWh	362,578,407	2.787 ¢	$10,105,060	2.7806%	$9,771,926		2.695 ¢	$9,771,488
Off-Peak, per off-peak kWh	199,758,810	2.737 ¢	$5,467,399	1.5045%	$5,287,155		2.645 ¢	$5,283,621
	562,337,217		$15,572,459		$15,059,082			$15,055,109
							Change	-$517,350
Primary Voltage								
On-Peak, per on-peak kWh	1,059,842,214	2.584 ¢	$27,386,323	7.5360%	$26,483,478		2.499 ¢	$26,485,457
Off-Peak, per off-peak kWh	666,622,616	2.534 ¢	$16,892,217	4.6483%	$16,335,331		2.449 ¢	$16,325,588
	1,726,464,830		$44,278,540		$42,818,809			$42,811,045
							Change	-$1,467,495
Transmission Voltage								
On-Peak, per on-peak kWh	237,834,835	2.427 ¢	$5,772,251	1.5884%	$5,581,957		2.349 ¢	$5,586,740
Off-Peak, per off-peak kWh	181,976,894	2.377 ¢	$4,325,591	1.1903%	$4,182,989		2.299 ¢	$4,183,649
	419,811,729		$10,097,842		$9,764,946			$9,770,389
							Change	-$327,453
Schedule 15, Outdoor Area Lighting Service								
Secondary Voltage								
All kWh, per kWh	9,366,492	2.278 ¢	$213,371	0.0587%	$206,337		2.203 ¢	$206,032
	9,366,492		$213,371		$206,337			$206,032
							Change	-$7,339
Schedule 50, Mercury Vapor Street Lighting Service								
Secondary Voltage								
All kWh, per kWh	7,781,826	1.877 ¢	$146,352	0.0403%	$141,527		1.819 ¢	$141,374
	7,781,826		$146,352		$141,527			$141,374
							Change	-$4,979
Schedule 51, Street Lighting Service, Company-Owned System								
Secondary Voltage								
All kWh, per kWh	19,908,344	2.963 ¢	$589,355	0.1622%	$569,926		2.863 ¢	$569,900
	19,908,344		$589,355		$569,926			$569,900
							Change	-$19,455
Schedule 52, Street Lighting Service, Company-Owned System								
Secondary Voltage								
All kWh, per kWh	400,697	2.265 ¢	$9,076	0.0025%	$8,777		2.190 ¢	$8,775
	400,697		$9,076		$8,777			$8,775
							Change	-$301
Schedule 53, Street Lighting Service, Consumer-Owned System								
Secondary Voltage								
All kWh, per kWh	9,910,325	0.966 ¢	$95,734	0.0263%	$92,578		0.934 ¢	$92,562
	9,910,325		$95,734		$92,578			$92,562
							Change	-$3,171
Schedule 54, Recreational Field Lighting								
Secondary Voltage								
All kWh, per kWh	1,464,102	1.666 ¢	$24,392	0.0067%	$23,588		1.611 ¢	$23,587
	1,464,102		$24,392		$23,588			$23,587
							Change	-$805
Total before Employee Discount			**$366,853,612**	100.0000%	$354,760,589			**$354,756,661**
Employee Discount			-$125,273		-$121,141			-$121,141
TOTAL	**12,860,943,252**		**$366,728,340**		$354,639,448			**$354,635,520**
							Change	**-$12,092,820**
Schedule 47 Unscheduled kWh	3,131,805							
Total Forecast kWH	12,864,075,057							

Docket No. UE 307
Exhibit PAC/703
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Judith M. Ridenour

Proposed Reply TAM Adjustment for Other Items

August 2016

PACIFIC POWER
STATE OF OREGON
TAM Schedule 205 - TAM Adjustment for Other Items
Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2017

Rate Schedule	Forecast Energy	Present Schedule 205 Rates	Generation Based Rate Spread	Proposed Adj. to Schedule 205 for Other Revenues: Rates	Proposed Adj. to Schedule 205 for Other Revenues: Revenues	Total Proposed Schedule 205 Rates
Schedule 4, Residential						
First Block kWh (0-1,000)	3,866,192,250	0.013 ¢	29.0330%	0.009 ¢	$347,957	0.022 ¢
Second Block kWh (> 1,000)	1,363,856,082	0.017 ¢	13.9910%	0.012 ¢	$163,663	0.029 ¢
	5,230,048,332				$511,620	
Employee Discount						
First Block kWh (0-1,000)	11,175,059			0.009 ¢	$1,006	
Second Block kWh (> 1,000)	5,260,850			0.012 ¢	$631	
	16,435,909				$1,637	
Discount					-$409	
Schedule 23, Small General Service						
Secondary Voltage						
1st 3,000 kWh, per kWh	871,764,198	0.014 ¢	7.2517%	0.010 ¢	$87,176	0.024 ¢
All additional kWh, per kWh	234,196,016	0.011 ¢	1.4448%	0.007 ¢	$16,394	0.018 ¢
	1,105,960,214				$103,570	
Primary Voltage						
1st 3,000 kWh, per kWh	738,519	0.014 ¢	0.0060%	0.009 ¢	$66	0.023 ¢
All additional kWh, per kWh	329,186	0.010 ¢	0.0020%	0.007 ¢	$23	0.017 ¢
	1,067,705				$89	
Schedule 28, General Service 31-200kW						
Secondary Voltage						
1st 20,000 kWh, per kWh	1,427,143,857	0.014 ¢	11.6085%	0.009 ¢	$128,443	0.023 ¢
All additional kWh, per kWh	582,416,811	0.013 ¢	4.6076%	0.009 ¢	$52,418	0.022 ¢
	2,009,560,668				$180,861	
Primary Voltage						
1st 20,000 kWh, per kWh	9,801,024	0.014 ¢	0.0768%	0.009 ¢	$882	0.023 ¢
All additional kWh, per kWh	8,837,541	0.013 ¢	0.0674%	0.009 ¢	$795	0.022 ¢
	18,638,565				$1,677	
Schedule 30, General Service 201-999kW						
Secondary Voltage						
1st 20,000 kWh, per kWh	184,702,861	0.015 ¢	1.6061%	0.010 ¢	$18,470	0.025 ¢
All additional kWh, per kWh	1,086,874,572	0.013 ¢	8.1947%	0.009 ¢	$97,819	0.022 ¢
	1,271,577,433				$116,289	
Primary Voltage						
1st 20,000 kWh, per kWh	12,525,631	0.014 ¢	0.1077%	0.010 ¢	$1,253	0.024 ¢
All additional kWh, per kWh	80,863,348	0.013 ¢	0.6010%	0.009 ¢	$7,278	0.022 ¢
	93,388,979				$8,531	
Schedule 41, Agricultural Pumping Service						
Secondary Voltage						
Winter, 1st 100 kWh/kW, per kWh	2,915,053	0.020 ¢	0.0339%	0.013 ¢	$379	0.033 ¢
Winter, All additional kWh, per kWh	2,478,448	0.014 ¢	0.0196%	0.009 ¢	$223	0.023 ¢
Summer, All kWh, per kWh	227,452,860	0.014 ¢	1.8001%	0.009 ¢	$20,471	0.023 ¢
	232,846,361				$21,073	
Primary Voltage						
Winter, 1st 100 kWh/kW, per kWh	10,164	0.019 ¢	0.0001%	0.013 ¢	$1	0.032 ¢
Winter, All additional kWh, per kWh	58,136	0.013 ¢	0.0004%	0.009 ¢	$5	0.022 ¢
Summer, All kWh, per kWh	361,344	0.013 ¢	0.0028%	0.009 ¢	$33	0.022 ¢
	429,644				$39	
Schedule 47, Large General Service, Partial Requirements 1,000kW and over						
Primary Voltage						
On-Peak, per on-peak kWh	35,574,864	0.012 ¢		0.008 ¢	$2,846	0.020 ¢
Off-Peak, per off-peak kWh	12,536,048	0.012 ¢		0.008 ¢	$1,003	0.020 ¢
	48,110,912				$3,849	
Transmission Voltage						
On-Peak, per on-peak kWh	49,897,565	0.011 ¢		0.007 ¢	$3,493	0.018 ¢
Off-Peak, per off-peak kWh	41,971,311	0.011 ¢		0.007 ¢	$2,938	0.018 ¢
	91,868,876				$6,431	

PACIFIC POWER
STATE OF OREGON
TAM Schedule 205 - TAM Adjustment for Other Items
Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2017

Rate Schedule	Forecast Energy	Present Schedule 205 Rates	Generation Based Rate Spread	Proposed Adj. to Schedule 205 for Other Revenues		Total Proposed Schedule 205 Rates
				Rates	Revenues	
Schedule 48, Large General Service, 1,000kW and over						
Secondary Voltage						
On-Peak, per on-peak kWh	362,578,407	0.013 ¢	2.7806%	0.009 ¢	$32,632	0.022 ¢
Off-Peak, per off-peak kWh	199,758,810	0.013 ¢	1.5045%	0.009 ¢	$17,978	0.022 ¢
	562,337,217				$50,610	
Primary Voltage						
On-Peak, per on-peak kWh	1,059,842,214	0.012 ¢	7.5360%	0.008 ¢	$84,787	0.020 ¢
Off-Peak, per off-peak kWh	666,622,616	0.012 ¢	4.6483%	0.008 ¢	$53,330	0.020 ¢
	1,726,464,830				$138,117	
Transmission Voltage						
On-Peak, per on-peak kWh	237,834,835	0.011 ¢	1.5884%	0.007 ¢	$16,648	0.018 ¢
Off-Peak, per off-peak kWh	181,976,894	0.011 ¢	1.1903%	0.007 ¢	$12,738	0.018 ¢
	419,811,729				$29,386	
Schedule 15, Outdoor Area Lighting Service						
Secondary Voltage						
All kWh, per kWh	9,366,492	0.011 ¢	0.0587%	0.007 ¢	$355	0.018 ¢
	9,366,492				$355	
Schedule 50, Mercury Vapor Street Lighting Service						
Secondary Voltage						
All kWh, per kWh	7,781,826	0.009 ¢	0.0403%	0.006 ¢	$107	0.015 ¢
	7,781,826				$107	
Schedule 51, Street Lighting Service, Company-Owned System						
Secondary Voltage						
All kWh, per kWh	19,908,344	0.013 ¢	0.1622%	0.009 ¢	$1,745	0.022 ¢
	19,908,344				$1,745	
Schedule 52, Street Lighting Service, Company-Owned System						
Secondary Voltage						
All kWh, per kWh	400,697	0.011 ¢	0.0025%	0.007 ¢	$28	0.018 ¢
	400,697				$28	
Schedule 53, Street Lighting Service, Consumer-Owned System						
Secondary Voltage						
All kWh, per kWh	9,910,325	0.005 ¢	0.0263%	0.003 ¢	$297	0.008 ¢
	9,910,325				$297	
Schedule 54, Recreational Field Lighting						
Secondary Voltage						
All kWh, per kWh	1,464,102	0.007 ¢	0.0067%	0.005 ¢	$73	0.012 ¢
	1,464,102				$73	
Total before Employee Discount			**100.0000%**		**$1,174,747**	
Employee Discount					-$409	
TOTAL	**12,860,943,252**				**$1,174,338**	
Schedule 47 Unscheduled kWh	3,131,805					
Total Forecast kWH	12,864,075,057					

Docket No. UE 307
Exhibit PAC/704
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Judith M. Ridenour

Proposed Reply Tariff Schedules

August 2016

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 200

BASE SUPPLY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To all Residential Consumers and Nonresidential Consumers. This service may be taken only in conjunction with the applicable Delivery Service Schedule or Direct Access Delivery Service Schedule. Not applicable to energy usage under Delivery Service Schedule 76 which is billed at Economic Replacement Power rates under Schedule 276 or energy usage under Delivery Service Schedule 47 which is billed at Unscheduled Energy rates under Schedule 247.

Monthly Billing

The Monthly Billing shall be the Energy Charge and/or Demand Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage**			
			Secondary	**Primary**	**Transmission**	
4	Per kWh	0 – 1000 kWh	2.927¢			(I)
		> 1000 kWh	3.996 ¢			(I)
5	Per kWh	0 – 1000 kWh	2.927¢			(I)
		> 1000 kWh	3.996¢			(I)

For Schedules 4 and 5, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).

		Secondary	Primary	Transmission	
23, 723	First 3,000 kWh, per kWh	3.365¢	3.271¢		(I)
	All additional kWh, per kWh	2.498¢	2.427¢		(I)
28, 728	First 20,000 kWh, per kWh	3.304¢	3.108¢		(I)
	All additional kWh, per kWh	3.216¢	3.024¢		(I)
30, 730	Demand Charge, per kW	$1.88	$1.88		(I)
	First 20,000 kWh, per kWh	2.860¢	2.789¢		(I)
	All additional kWh, per kWh	2.480¢	2.411¢		(I)

Demand shall be as defined in the Delivery Service Schedule

		Secondary	Primary	Transmission	
41, 741	Winter, first 100 kWh/kW, per kWh	4.629¢	4.497¢		(I)
	Winter, all additional kWh, per kWh	3.156 ¢	3.066¢		(I)
	Summer, all kWh, per kWh	3.156¢	3.066¢		(I)

For Schedule 41, Winter is defined as service rendered from December 1 through March 31, Summer is defined as service rendered April 1 through November 30.

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		**Delivery Voltage** Secondary	Primary	Transmission	
47/48, 747/748	Demand Charge, per kW of On-Peak Demand	$1.83	$1.87	$1.88	(I)
	Per kWh, On-Peak	2.581¢	2.443¢	2.353¢	(I)
	Per kWh, Off-Peak	2.531¢	2.393¢	2.303¢	(I)

For Schedule 47 and Schedule 48, On-Peak hours are from 6:00 a.m. to 10:00 p.m. Monday through Saturday excluding NERC holidays. Off-Peak hours are remaining hours.

On-Peak Demand shall be as defined in the Delivery Service Schedule.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

52, 752	For dusk to dawn operation, per kWh	2.477¢	(I)
	For dusk to midnight operation, per kWh	2.477¢	(I)
54, 754	Per kWh	1.820¢	(I)

15	**Type of Luminaire**	**Nominal Rating**	**Monthly kWh**	**Rate Per Luminaire**	
	Mercury Vapor	7,000	76	$1.73	(I)
	Mercury Vapor	21,000	172	$3.90	(I)
	Mercury Vapor	55,000	412	$9.35	(I)
	High Pressure Sodium	5,800	31	$0.70	(I)
	High Pressure Sodium	22,000	85	$1.93	(I)
	High Pressure Sodium	50,000	176	$4.00	(I)

50 **A. Company-owned Overhead System**
Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
Horizontal, per lamp	$1.56	$3.52	$8.43	(I)
Vertical, per lamp	$1.56	$3.52		(I)

Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.56			(I)
On 26-foot poles, vertical, per lamp	$1.56			(I)
On 30-foot poles, horizontal, per lamp		$3.52		(I)
On 30-foot poles, vertical, per lamp		$3.52		(I)
On 33-foot poles, horizontal, per lamp			$8.43	(I)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

50 **B. Company-owned Underground System**

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.56			(I)
On 26-foot poles, vertical, per lamp	$1.56			(I)
On 30-foot poles, horizontal, per lamp		$3.52		(I)
On 30-foot poles, vertical, per lamp		$3.52		(I)
On 33-foot poles, horizontal, per lamp			$8.43	(I)

51, 751

Types of Luminaire	**Nominal rating**	**Watts**	**Monthly kWh**	**Rate Per Luminaire**	
LED	4,000	100 (comp)		$0.61	(I)
LED	6,200	150 (comp)		$0.87	(I)
LED	13,000	250 (comp)		$1.65	(I)
LED	16,800	400 (comp)		$2.23	(I)
High Pressure Sodium	5,800	70	31	$1.00	(I)
High Pressure Sodium	9,500	100	44	$1.42	(I)
High Pressure Sodium	16,000	150	64	$2.07	(I)
High Pressure Sodium	22,000	200	85	$2.75	(I)
High Pressure Sodium	27,500	250	115	$3.72	(I)
High Pressure Sodium	50,000	400	176	$5.69	(I)
Metal Halide	12,000	175	68	$2.20	(I)
Metal Halide	19,500	250	94	$3.04	(I)

53, 753

Types of Luminaire	**Nominal rating**	**Watts**	**Monthly kWh**	**Rate Per Luminaire**	
High Pressure Sodium	5,800	70	31	$0.33	(I)
High Pressure Sodium	9,500	100	44	$0.47	(I)
High Pressure Sodium	16,000	150	64	$0.68	(I)
High Pressure Sodium	22,000	200	85	$0.90	(I)
High Pressure Sodium	27,500	250	115	$1.22	(I)
High Pressure Sodium	50,000	400	176	$1.86	(I)
Metal Halide	9,000	100	39	$0.41	(I)
Metal Halide	12,000	175	68	$0.72	(I)
Metal Halide	19,500	250	94	$0.99	(I)
Metal Halide	32,000	400	149	$1.57	(I)
Metal Halide	107,800	1,000	354	$3.74	(I)
Non-Listed Luminaire, per kWh			1.057¢		(I)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 201

NET POWER COSTS
COST-BASED SUPPLY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Residential Consumers and Nonresidential Consumers who have elected to take Cost-Based Supply Service under this schedule or under Schedules 210, 211, 212, 213 or 247. This service may be taken only in conjunction with the applicable Delivery Service Schedule. Also applicable to Nonresidential Consumers who, based on the announcement date defined in OAR 860-038-275, do not elect to receive standard offer service under Schedule 220 or direct access service under the applicable tariff. In addition, applicable to some Large Nonresidential Consumers on Schedule 400 whose special contracts require prices under the Company's previously applicable Schedule 48T. For Consumers on Schedule 400 who were served on previously applicable Schedule 48T prices under their special contract, this service, in conjunction with Delivery Service Schedule 48, supersedes previous Schedule 48T.

Nonresidential Consumers who had chosen either service under Schedule 220 or who chose to receive direct access service under the applicable tariff may qualify to return to Cost-Based Supply Service under this Schedule after meeting the Returning Service Requirements and making a Returning Service Payment as specified in this Schedule.

Monthly Billing

The Monthly Billing shall be the Energy Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage**			
			Secondary	**Primary**	**Transmission**	
4	Per kWh	0-1000 kWh	2.639¢			(R)
		> 1000 kWh	3.605¢			(R)
5	Per kWh	0-1000 kWh	2.639¢			(R)
		> 1000 kWh	3.605¢			(R)

For Schedules 4 and 5, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).

		Secondary	**Primary**	**Transmission**	
23	First 3,000 kWh, per kWh	2.923¢	2.831 ¢		(R)
	All additional kWh, per kWh	2.168¢	2.100¢		(R)
28	First 20,000 kWh, per kWh	2.859¢	2.752¢		(R)
	All additional kWh, per kWh	2.780¢	2.679¢		(R)
30	First 20,000 kWh, per kWh	3.056¢	3.022¢		(R)
	All additional kWh, per kWh	2.650¢	2.612¢		(R)
41	Winter, first 100 kWh/kW, per kWh	4.082¢	3.948¢		(R)
	Winter, all additional kWh, per kWh	2.781¢	2.694¢		(R)
	Summer, all kWh, per kWh	2.781¢	2.694¢		(R)

For Schedule 41, Winter is defined as service rendered from December 1 through March 31, Summer is defined as service rendered April 1 through November 30.

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		**Secondary**	**Primary**	**Transmission**	
			Delivery Voltage		
47/48	Per kWh On-Peak	2.695¢	2.499¢	2.349¢	(R)
	Per kWh, Off-Peak	2.645¢	2.449¢	2.299¢	(R)

For Schedule 47 and Schedule 48, On-Peak hours are from 6:00 a.m. to 10:00 p.m. Monday through Saturday excluding NERC holidays. Off-Peak hours are remaining hours.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

52	For dusk to dawn operation, per kWh	2.190¢	(R)
	For dusk to midnight operation, per kWh	2.190¢	(R)
54	Per kWh	1.611¢	(R)

	Type of Luminaire	**Nominal Rating**	**Monthly kWh**	**RatePer Luminaire**	
15	Mercury Vapor	7,000	76	$ 1.67	(R)
	Mercury Vapor	21,000	172	$ 3.79	(R)
	Mercury Vapor	55,000	412	$ 9.08	(R)
	High Pressure Sodium	5,800	31	$ 0.68	(R)
	High Pressure Sodium	22,000	85	$ 1.87	(R)
	High Pressure Sodium	50,000	176	$ 3.88	(R)

50 **A. Company-owned Overhead System**
Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
Horizontal, per lamp	$1.38	$3.13	$7.49	(R)
Vertical, per lamp	$1.38	$3.13		(R)

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.38			(R)
On 26-foot poles, vertical, per lamp	$1.38			(R)
On 30-foot poles, horizontal, per lamp		$3.13		(R)
On 30-foot poles, vertical, per lamp		$3.13		(R)
On 33-foot poles, horizontal, per lamp			$7.49	(R)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

50 **B. Company-owned Underground System**

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.38			(R)
On 26-foot poles, vertical, per lamp	$1.38			(R)
On 30-foot poles, horizontal, per lamp		$3.13		(R)
On 30-foot poles, vertical, per lamp		$3.13		(R)
On 33-foot poles, horizontal, per lamp			$7.49	(R)

51

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
LED	4,000	100 (comp)		$0.54	(R)
LED	6,200	150 (comp)		$0.77	(R)
LED	13,000	250 (comp)		$1.46	(R)
LED	16,800	400 (comp)		$1.98	(R)
High Pressure Sodium	5,800	70	31	$0.89	(R)
High Pressure Sodium	9,500	100	44	$1.26	(R)
High Pressure Sodium	16,000	150	64	$1.83	(R)
High Pressure Sodium	22,000	200	85	$2.43	(R)
High Pressure Sodium	27,500	250	115	$3.29	(R)
High Pressure Sodium	50,000	400	176	$5.04	(R)
Metal Halide	12,000	175	68	$1.95	(R)
Metal Halide	19,500	250	94	$2.69	(R)

53

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$0.29	(R)
High Pressure Sodium	9,500	100	44	$0.41	(R)
High Pressure Sodium	16,000	150	64	$0.60	(R)
High Pressure Sodium	22,000	200	85	$0.79	(R)
High Pressure Sodium	27,500	250	115	$1.07	(R)
High Pressure Sodium	50,000	400	176	$1.64	(R)
Metal Halide	9,000	100	39	$0.36	(R)
Metal Halide	12,000	175	68	$0.64	(R)
Metal Halide	19,500	250	94	$0.88	(R)
Metal Halide	32,000	400	149	$1.39	(R)
Metal Halide	107,800	1,000	354	$3.31	(R)

Non-Listed Luminaire, per kWh 0.934¢ (R)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 205

TAM ADJUSTMENT FOR OTHER ITEMS (C)

Purpose

This schedule adjusts rates for Other Revenues as authorized by Order No. 10-363.

Applicable

To all Residential Consumers and Nonresidential Consumers.

Energy Charge

The adjustment rate is listed below by Delivery Service Schedule and Direct Access Delivery Service Schedule.

Delivery Service Schedule No.			Delivery Voltage Secondary	Primary	Transmission	
4	Per kWh	0-1000 kWh	0.022¢			(I)
		> 1000 kWh	0.029¢			(I)
5	Per kWh	0-1000 kWh	0.022¢			(I)
		> 1000 kWh	0.029¢			(I)

For Schedules 4 and 5, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).

Delivery Service Schedule No.		Secondary	Primary	Transmission	
23, 723	First 3,000 kWh, per kWh	0.024¢	0.023¢		(I)
	All additional kWh, per kWh	0.018¢	0.017¢		(I)
28, 728	First 20,000 kWh, per kWh	0.023¢	0.023¢		(I)
	All additional kWh, per kWh	0.022¢	0.022¢		(I)
30, 730	First 20,000 kWh, per kWh	0.025¢	0.024¢		(I)
	All additional kWh, per kWh	0.022¢	0.022¢		(I)
41, 741	Winter, first 100 kWh/kW, per kWh	0.033¢	0.032¢		(I)
	Winter, all additional kWh, per kWh	0.023¢	0.022¢		(I)
	Summer, all kWh, per kWh	0.023¢	0.022¢		(I)

For Schedule 41, Winter is defined as service rendered from December 1 through March 31, Summer is defined as service rendered April 1 through November 30.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 205

TAM ADJUSTMENT FOR OTHER ITEMS

 (C)

Energy Charge (continued)

Delivery Service Schedule No.		**Delivery Voltage** Secondary	Primary	Transmission	
47/48	Per kWh On-Peak	0.022¢	0.020¢	0.018¢	(I)
747/748	Per kWh, Off-Peak	0.022¢	0.020¢	0.018¢	(I)

For Schedule 47 and Schedule 48, On-Peak hours are from 6:00 a.m. to 10:00 p.m. Monday through Saturday excluding NERC holidays. Off-Peak hours are remaining hours.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

52, 752	For dusk to dawn operation, per kWh	0.018¢	(I)
	For dusk to midnight operation, per kWh	0.018¢	(I)
54,754	Per kWh	0.012¢	(I)

15

Type of Luminaire	**Nominal Rating**	**Monthly kWh**	**RatePer Luminaire**	
Mercury Vapor	7,000	76	$0.01	
Mercury Vapor	21,000	172	$0.03	(I)
Mercury Vapor	55,000	412	$0.07	(I)
High Pressure Sodium	5,800	31	$0.01	(I)
High Pressure Sodium	22,000	85	$0.02	(I)
High Pressure Sodium	50,000	176	$0.03	(I)

50 **A. Company-owned Overhead System**

Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
Horizontal, per lamp	$0.01	$0.03	$0.06	(I)
Vertical, per lamp	$0.01	$0.03		(I)

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$0.01			
On 26-foot poles, vertical, per lamp	$0.01			
On 30-foot poles, horizontal, per lamp		$0.03		(I)
On 30-foot poles, vertical, per lamp		$0.03		(I)
On 33-foot poles, horizontal, per lamp			$0.06	(I)

(continued)

Energy Charge (continued)

Delivery Service Schedule No.

50 **B. Company-owned Underground System**

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$0.01			
On 26-foot poles, vertical, per lamp	$0.01			
On 30-foot poles, horizontal, per lamp		$0.03		(I)
On 30-foot poles, vertical, per lamp		$0.03		(I)
On 33-foot poles, horizontal, per lamp			$0.06	(I)

51, 751

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
LED	4,000	100 (comp)		$0.00	
LED	6,200	150 (comp)		$0.01	(I)
LED	13,000	250 (comp)		$0.01	
LED	16,800	400 (comp)		$0.02	(I)
High Pressure Sodium	5,800	70	31	$0.01	(I)
High Pressure Sodium	9,500	100	44	$0.01	
High Pressure Sodium	16,000	150	64	$0.01	
High Pressure Sodium	22,000	200	85	$0.02	(I)
High Pressure Sodium	27,500	250	115	$0.03	(I)
High Pressure Sodium	50,000	400	176	$0.04	(I)
Metal Halide	12,000	175	68	$0.01	
Metal Halide	19,500	250	94	$0.02	(I)

53, 753

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$0.00	
High Pressure Sodium	9,500	100	44	$0.00	
High Pressure Sodium	16,000	150	64	$0.01	(I)
High Pressure Sodium	22,000	200	85	$0.01	(I)
High Pressure Sodium	27,500	250	115	$0.01	
High Pressure Sodium	50,000	400	176	$0.01	
Metal Halide	9,000	100	39	$0.00	
Metal Halide	12,000	175	68	$0.01	(I)
Metal Halide	19,500	250	94	$0.01	(I)
Metal Halide	32,000	400	149	$0.01	
Metal Halide	107,800	1,000	354	$0.03	(I)

Non-Listed Luminaire, per kWh 0.008¢ (I)

Docket No. UE 307
Exhibit PAC/705
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Judith M. Ridenour

Estimated Effect of Proposed Reply TAM Price Change

August 2016

TAM

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDING DECEMBER 31, 2017

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	490,463	5,230,048	$597,765	$7,793	$605,558	$604,457	$7,793	$612,250	$6,692	1.1%	$6,692	1.1%	1
2	**Total Residential**		490,463	5,230,048	$597,765	$7,793	$605,558	$604,457	$7,793	$612,250	$6,692	1.1%	$6,692	1.1%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	78,294	1,107,028	$121,654	$5,447	$127,101	$123,089	$5,447	$128,536	$1,435	1.2%	$1,435	1.1%	3
4	Gen. Svc. 31 - 200 kW	28	9,997	2,028,199	$183,967	$3,873	$187,840	$186,680	$3,873	$190,553	$2,713	1.5%	$2,713	1.4%	4
5	Gen. Svc. 201 - 999 kW	30	810	1,364,966	$110,135	$1,542	$111,677	$111,813	$1,542	$113,355	$1,678	1.5%	$1,678	1.5%	5
6	Large General Service >= 1,000 kW	48	187	2,708,614	$193,506	($6,456)	$187,050	$196,632	($6,456)	$190,176	$3,126	1.6%	$3,126	1.7%	6
7	Partial Req. Svc. >= 1,000 kW	47	7	143,112	$12,104	($418)	$11,686	$12,289	($418)	$11,871	$185	1.6%	$185	1.7%	7
8	Agricultural Pumping Service	41	7,950	233,276	$26,924	($1,183)	$25,741	$27,224	($1,183)	$26,041	$300	1.1%	$300	1.2%	8
9	**Total Commercial & Industrial**		97,245	7,585,195	$648,290	$2,805	$651,095	$657,727	$2,805	$660,532	$9,437	1.5%	$9,437	1.5%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,424	9,366	$1,203	$227	$1,430	$1,210	$227	$1,437	$7	0.6%	$7	0.5%	10
11	Street Lighting Service	50	227	7,782	$864	$174	$1,038	$870	$174	$1,044	$6	0.7%	$6	0.6%	11
12	Street Lighting Service HPS	51	781	19,908	$3,488	$731	$4,219	$3,513	$731	$4,244	$25	0.7%	$25	0.6%	12
13	Street Lighting Service	52	35	401	$52	$9	$61	$53	$9	$62	$1	1.9%	$1	1.6%	13
14	Street Lighting Service	53	257	9,910	$622	$126	$748	$626	$126	$752	$4	0.6%	$4	0.5%	14
15	Recreational Field Lighting	54	107	1,464	$121	$23	$144	$122	$23	$145	$1	0.8%	$1	0.7%	15
16	**Total Public Street Lighting**		7,831	48,831	$6,350	$1,290	$7,640	$6,394	$1,290	$7,684	$44	0.7%	$44	0.6%	16
17	**Total Sales before Emp. Disc. & AGA**		595,539	12,864,074	$1,252,405	$11,888	$1,264,293	$1,268,578	$11,888	$1,280,466	$16,173	1.3%	$16,173	1.3%	17
18	Employee Discount				($464)	($3)	($467)	($470)	($3)	($473)	($6)		($6)		18
19	**Total Sales with Emp. Disc**		595,539	12,864,074	$1,251,941	$11,885	$1,263,826	$1,268,108	$11,885	$1,279,993	$16,167	1.3%	$16,167	1.3%	19
20	AGA Revenue				$2,439		$2,439	$2,439		$2,439	$0		$0		20
21	**Total Sales**		595,539	12,864,074	$1,254,380	$11,885	$1,266,265	$1,270,547	$11,885	$1,282,432	$16,167	1.3%	$16,167	1.3%	21

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$20.25	$20.37	$0.12	0.59%
200	$29.86	$30.11	$0.25	0.84%
300	$39.49	$39.85	$0.36	0.91%
400	$49.12	$49.61	$0.49	1.00%
500	$58.75	$59.35	$0.60	1.02%
600	$68.37	$69.09	$0.72	1.05%
700	$78.00	$78.85	$0.85	1.09%
800	$87.63	$88.59	$0.96	1.10%
900	**$97.24**	**$98.33**	**$1.09**	**1.12%**
950	$102.07	$103.21	$1.14	1.12%
1,000	$106.87	$108.08	$1.21	1.13%
1,100	$119.60	$120.97	$1.37	1.15%
1,200	$132.31	$133.84	$1.53	1.16%
1,300	$145.04	$146.74	$1.70	1.17%
1,400	$157.77	$159.62	$1.85	1.17%
1,500	$170.50	$172.52	$2.02	1.18%
1,600	$183.21	$185.40	$2.19	1.20%
2,000	$234.11	$236.95	$2.84	1.21%
3,000	$361.34	$365.82	$4.48	1.24%
4,000	$488.58	$494.70	$6.12	1.25%
5,000	$615.82	$623.57	$7.75	1.26%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

kW		Monthly Billing*				Percent	
		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$71	$80	$72	$81	0.98%	0.89%
	750	$98	$107	$99	$108	1.08%	0.99%
	1,000	$125	$133	$126	$135	1.13%	1.06%
	1,500	$178	$187	$180	$189	1.19%	1.13%
10	1,000	$125	$133	$126	$135	1.13%	1.06%
	2,000	$231	$240	$234	$243	1.22%	1.18%
	3,000	$338	$347	$342	$351	1.25%	1.22%
	4,000	$428	$437	$434	$442	1.23%	1.21%
20	4,000	$455	$464	$461	$469	1.16%	1.14%
	6,000	$636	$645	$643	$652	1.16%	1.14%
	8,000	$817	$825	$826	$835	1.16%	1.15%
	10,000	$997	$1,006	$1,009	$1,018	1.16%	1.15%
30	9,000	$961	$970	$971	$980	1.10%	1.09%
	12,000	$1,232	$1,241	$1,245	$1,254	1.11%	1.10%
	15,000	$1,503	$1,512	$1,520	$1,528	1.12%	1.11%
	18,000	$1,774	$1,783	$1,794	$1,803	1.13%	1.12%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

		Monthly Billing*				Percent Difference	
		Present Price		Proposed Price			
kW Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$70	$79	$71	$79	0.97%	0.88%
	750	$96	$105	$97	$106	1.08%	0.98%
	1,000	$122	$131	$123	$132	1.13%	1.05%
	1,500	$174	$183	$176	$185	1.18%	1.13%
10	1,000	$122	$131	$123	$132	1.13%	1.05%
	2,000	$226	$234	$228	$237	1.21%	1.17%
	3,000	$330	$338	$334	$342	1.25%	1.21%
	4,000	$418	$426	$423	$431	1.23%	1.20%
20	4,000	$444	$453	$449	$458	1.16%	1.13%
	6,000	$620	$629	$627	$636	1.16%	1.14%
	8,000	$796	$805	$805	$814	1.16%	1.14%
	10,000	$972	$980	$983	$992	1.16%	1.15%
30	9,000	$936	$945	$947	$955	1.09%	1.08%
	12,000	$1,200	$1,209	$1,214	$1,222	1.11%	1.10%
	15,000	$1,464	$1,473	$1,480	$1,489	1.12%	1.11%
	18,000	$1,728	$1,737	$1,747	$1,756	1.12%	1.12%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	3,000	$347	$351	1.20%
	4,500	$458	$464	1.37%
	7,500	$680	$691	1.53%
31	6,200	$697	$705	1.24%
	9,300	$927	$939	1.40%
	15,500	$1,386	$1,407	1.56%
40	8,000	$894	$905	1.24%
	12,000	$1,190	$1,207	1.40%
	20,000	$1,783	$1,811	1.56%
60	12,000	$1,332	$1,349	1.25%
	18,000	$1,777	$1,802	1.41%
	30,000	$2,649	$2,690	1.56%
80	16,000	$1,765	$1,787	1.26%
	24,000	$2,351	$2,384	1.41%
	40,000	$3,509	$3,564	1.56%
100	20,000	$2,197	$2,225	1.27%
	30,000	$2,921	$2,963	1.41%
	50,000	$4,369	$4,437	1.56%
200	40,000	$4,302	$4,357	1.27%
	60,000	$5,750	$5,832	1.42%
	100,000	$8,646	$8,781	1.57%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$445	$451	1.30%
	6,000	$547	$554	1.41%
	7,500	$648	$658	1.49%
31	9,300	$894	$906	1.34%
	12,400	$1,104	$1,119	1.45%
	15,500	$1,313	$1,333	1.52%
40	12,000	$1,146	$1,162	1.35%
	16,000	$1,417	$1,437	1.45%
	20,000	$1,687	$1,713	1.53%
60	18,000	$1,709	$1,733	1.36%
	24,000	$2,108	$2,139	1.46%
	30,000	$2,504	$2,542	1.53%
80	24,000	$2,259	$2,290	1.36%
	32,000	$2,786	$2,827	1.46%
	40,000	$3,314	$3,365	1.54%
100	30,000	$2,805	$2,843	1.37%
	40,000	$3,464	$3,515	1.47%
	50,000	$4,124	$4,188	1.54%
200	60,000	$5,500	$5,576	1.38%
	80,000	$6,819	$6,920	1.48%
	100,000	$8,138	$8,264	1.55%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	20,000	$2,622	$2,656	1.28%
	30,000	$3,209	$3,251	1.32%
	50,000	$4,382	$4,442	1.37%
200	40,000	$4,603	$4,667	1.40%
	60,000	$5,776	$5,858	1.42%
	100,000	$8,121	$8,239	1.45%
300	60,000	$6,753	$6,848	1.41%
	90,000	$8,512	$8,634	1.43%
	150,000	$12,031	$12,206	1.45%
400	80,000	$8,785	$8,911	1.43%
	120,000	$11,131	$11,292	1.45%
	200,000	$15,822	$16,055	1.47%
500	100,000	$10,848	$11,005	1.44%
	150,000	$13,780	$13,981	1.46%
	250,000	$19,645	$19,934	1.47%
600	120,000	$12,911	$13,098	1.45%
	180,000	$16,429	$16,670	1.46%
	300,000	$23,467	$23,814	1.48%
800	160,000	$17,036	$17,285	1.46%
	240,000	$21,728	$22,048	1.47%
	400,000	$31,111	$31,573	1.48%
1000	200,000	$21,162	$21,473	1.47%
	300,000	$27,026	$27,426	1.48%
	500,000	$38,755	$39,332	1.49%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$3,147	$3,188	1.31%
	40,000	$3,722	$3,772	1.34%
	50,000	$4,297	$4,355	1.36%
200	60,000	$5,666	$5,746	1.41%
	80,000	$6,817	$6,914	1.42%
	100,000	$7,967	$8,081	1.43%
300	90,000	$8,346	$8,465	1.42%
	120,000	$10,072	$10,216	1.43%
	150,000	$11,797	$11,967	1.44%
400	120,000	$10,931	$11,088	1.44%
	160,000	$13,231	$13,423	1.45%
	200,000	$15,532	$15,758	1.45%
500	150,000	$13,528	$13,724	1.45%
	200,000	$16,404	$16,643	1.46%
	250,000	$19,280	$19,561	1.46%
600	180,000	$16,125	$16,360	1.46%
	240,000	$19,576	$19,862	1.46%
	300,000	$23,027	$23,365	1.47%
800	240,000	$21,319	$21,631	1.46%
	320,000	$25,921	$26,301	1.47%
	400,000	$30,522	$30,971	1.47%
1000	300,000	$26,513	$26,903	1.47%
	400,000	$32,265	$32,740	1.47%
	500,000	$38,017	$38,578	1.47%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	2,000	$190	$218	$155	$192	$221	$155	1.39%	1.49%	0.00%
	3,000	$285	$313	$155	$289	$317	$155	1.39%	1.46%	0.00%
	5,000	$474	$503	$155	$481	$510	$155	1.39%	1.43%	0.00%
Three Phase										
20	4,000	$380	$436	$309	$385	$442	$309	1.39%	1.49%	0.00%
	6,000	$569	$626	$309	$577	$635	$309	1.39%	1.46%	0.00%
	10,000	$949	$1,005	$309	$962	$1,020	$309	1.39%	1.43%	0.00%
100	20,000	$1,898	$2,179	$1,349	$1,924	$2,211	$1,349	1.39%	1.49%	0.00%
	30,000	$2,847	$3,128	$1,349	$2,886	$3,173	$1,349	1.39%	1.46%	0.00%
	50,000	$4,745	$5,026	$1,349	$4,811	$5,098	$1,349	1.39%	1.43%	0.00%
300	60,000	$5,694	$6,536	$3,409	$5,773	$6,633	$3,409	1.39%	1.49%	0.00%
	90,000	$8,541	$9,383	$3,409	$8,659	$9,520	$3,409	1.39%	1.46%	0.00%
	150,000	$14,234	$15,077	$3,409	$14,432	$15,292	$3,409	1.39%	1.43%	0.00%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$276	$303	$155	$279	$307	$155	1.39%	1.45%	0.00%
	4,000	$367	$395	$155	$373	$400	$155	1.39%	1.43%	0.00%
	5,000	$459	$487	$155	$466	$493	$155	1.39%	1.43%	0.00%
Three Phase										
20	6,000	$551	$606	$309	$559	$614	$309	1.39%	1.45%	0.00%
	8,000	$735	$789	$309	$745	$801	$309	1.39%	1.44%	0.00%
	10,000	$919	$973	$309	$931	$987	$309	1.39%	1.43%	0.00%
100	30,000	$2,756	$3,028	$1,339	$2,794	$3,072	$1,339	1.39%	1.45%	0.00%
	40,000	$3,675	$3,947	$1,339	$3,726	$4,003	$1,339	1.39%	1.44%	0.00%
	50,000	$4,593	$4,865	$1,339	$4,657	$4,935	$1,339	1.39%	1.43%	0.00%
300	90,000	$8,268	$9,084	$3,399	$8,383	$9,216	$3,399	1.39%	1.45%	0.00%
	120,000	$11,024	$11,840	$3,399	$11,177	$12,010	$3,399	1.39%	1.44%	0.00%
	150,000	$13,780	$14,596	$3,399	$13,972	$14,805	$3,399	1.39%	1.43%	0.00%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$26,399	$26,804	1.54%
	500,000	$37,660	$38,251	1.57%
	650,000	$46,106	$46,836	1.58%
2,000	600,000	$52,365	$53,176	1.55%
	1,000,000	$73,507	$74,690	1.61%
	1,300,000	$89,835	$91,295	1.63%
6,000	1,800,000	$153,427	$155,862	1.59%
	3,000,000	$218,739	$222,286	1.62%
	3,900,000	$267,722	$272,103	1.64%
12,000	3,600,000	$305,531	$310,401	1.59%
	6,000,000	$436,153	$443,248	1.63%
	7,800,000	$534,120	$542,883	1.64%

Notes:

On-Peak kWh	64.48%
Off-Peak kWh	35.52%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$24,948	$25,344	1.59%
	500,000	$35,393	$35,966	1.62%
	650,000	$43,227	$43,933	1.63%
2,000	600,000	$49,423	$50,214	1.60%
	1,000,000	$68,933	$70,078	1.66%
	1,300,000	$84,037	$85,448	1.68%
6,000	1,800,000	$144,199	$146,572	1.65%
	3,000,000	$204,614	$208,051	1.68%
	3,900,000	$249,926	$254,159	1.69%
12,000	3,600,000	$287,043	$291,789	1.65%
	6,000,000	$407,874	$414,746	1.68%
	7,800,000	$498,497	$506,964	1.70%

Notes:

On-Peak kWh	61.39%
Off-Peak kWh	38.61%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	500,000	$35,086	$35,659	1.64%
	650,000	$42,370	$43,077	1.67%
2,000	1,000,000	$67,906	$69,053	1.69%
	1,300,000	$81,910	$83,324	1.73%
6,000	3,000,000	$201,708	$205,150	1.71%
	3,900,000	$243,722	$247,961	1.74%
12,000	6,000,000	$401,268	$408,152	1.72%
	7,800,000	$485,295	$493,774	1.75%
50,000	25,000,000	$1,665,146	$1,693,832	1.72%
	32,500,000	$2,015,262	$2,050,591	1.75%

Notes:

On-Peak kWh	56.65%
Off-Peak kWh	43.35%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.