PACIFIC POWER
A DIVISION OF PACIFICORP

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July 11, 2017

VIA ELECTRONIC FILING,
OVERNIGHT DELIVERY,
AND HUDDLE

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

Re: UE 323 – PacifiCorp Reply Testimony and Exhibits

PacifiCorp d/b/a Pacific Power hereby submits for filing the Reply Testimony and Exhibits of Michael G. Wilding, Kelcey A. Brown, Dana M. Ralston and Seth Schwartz. Electronic workpapers will be posted to Huddle.

Please direct any informal correspondence and questions regarding this filing to Natasha Siores Manager, Regulatory Affairs, at (503) 813-6583.

Confidential material in support of the filing has been provided to parties under Order No. 16-128.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

CERTIFICATE OF SERVICE

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

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Dated this 11th day of July, 2017.

Jennifer Angell
Jennifer Angell
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Docket No. UE 323
Exhibit PAC/400
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Michael G. Wilding

July 2017

REPLY TESTIMONY OF MICHAEL G. WILDING

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ATTACHED EXHIBITS

Exhibit PAC/401 – 2018 TAM Allocation Reply Filing

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Exhibit PAC/403 – 2018 Corrections and Updates Summary Reply Filing

Exhibit PAC/404 – 2018 Other Revenue Reply Filing

Exhibit PAC/405 – 2018 EIM Costs Reply Filing

Exhibit PAC/406 – Notice 2017-33, 2017-22 IRB 1256, 05/26/2017, IRC Sec(s). 45

Exhibit PAC/407 – NERA's Report on Power Cost Adjustments and Act 162 Compliance

Exhibit PAC/408 – CONFIDENTIAL Staff Response to PacifiCorp Data Request 4

Exhibit PAC/409 – Staff Response to PacifiCorp Data Request 5

Exhibit PAC/410 – CUB Response to PacifiCorp Data Request 2

Q. Are you the same Michael G. Wilding who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp)?

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 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 PacifiCorp's revised Oregon net power costs (NPC) of $370.2 million for the test period of the 12 months ending December 31, 2018.[1] I provide corrections and contract, fuel, and forward price curve updates to the company's March 31, 2017, filing (initial filing).

Second, my reply testimony responds to various issues and adjustments raised in the Opening Testimony of Public Utility Commission of Oregon Staff (Staff) witnesses Mr. Scott Gibbens, Dr. Lance Kaufman, and Ms. Rose Anderson, Citizens' Utility Board of Oregon (CUB) witness Mr. Bob Jenks, Industrial Customers of Northwest Utilities (ICNU) witness Mr. Bradley G. Mullins, Sierra Club witness Dr. Thomas Vitolo, and Calpine Energy Solutions LLC (Calpine) witness Mr. Kevin Higgins.

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

A. There are three other witnesses providing reply testimony in support of PacifiCorp's

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

2018 TAM filing: Ms. Kelcey A. Brown, who testifies in support of the company's Energy Imbalance Market (EIM) benefit calculations, Mr. Dana M. Ralston, who testifies in support of PacifiCorp's coal costs, and Mr. Seth Schwartz, who testifies that the company coal contracts are prudent and consistent with industry standards.

Q. Please summarize your reply testimony.

A. PacifiCorp's reply update reflects a total rate impact of less than one percent. This modest increase is supported by robust evidence and relies on the same modeling refinements that were approved by the Commission in the 2016 TAM.

For the third time, parties challenge the day-ahead and real-time system balancing transactions adjustment (the DA/RT adjustment). Although the parties propose modifications to the adjustment, instead of recommending its outright rejection, the parties support their recommendations with largely the same recycled arguments as prior years and flawed analysis. Parties fail to reconcile their recommendations with the Commission's prior findings or differentiate them from those that have been rejected twice. Since first proposing the DA/RT adjustment, PacifiCorp has worked diligently to allow parties to understand the adjustment and has made modifications when reasonable, such as adopting CUB's normalization recommendations. Despite these efforts, the parties still present no realistic alternative to the DA/RT adjustment that captures the same costs and produces a more accurate NPC forecast.

Staff also proposes a significant change to the modeling of coal plant dispatch to model long-term economic shutdowns of coal units. Staff's adjustment, however, is admittedly based only on its "intuition" as to when coal plants might be shutdown, without any regard for the underlying operational considerations that would preclude these shutdowns in the real world. Staff's modeling also assumes, without evidentiary support, that the unusual market conditions that led to economic shutdowns in 2016 and 2017 will occur in 2018.

Staff again challenges PacifiCorp's modeling of EIM benefits, claiming that the company has understated the year-over-year growth rate in benefits. In response to Staff's concerns, the company has adjusted its modeling of EIM benefits to rely on the most recent validated operational data, which produces a robust growth rate that is tied directly to the market dynamics that drive the growth in EIM benefits. Staff's adjustment, on the other hand, is arbitrary and not grounded in the market realities that have increased PacifiCorp's EIM. As described by Ms. Brown, PacifiCorp's estimated EIM benefits have increased substantially since the 2016 TAM and reflect a reasonable, market-based, estimate for 2018.

Similar to the 2017 TAM, Staff and CUB have challenged PacifiCorp's modeling of new Qualifying Facilities (QFs) based on the contention that the company's modeling of new QFs has not accounted for operational delays. Neither party, however, has challenged the company's overall QF modeling or the undisputed evidence that the company has historically under-forecast QF generation. Staff and CUB instead unreasonably cherry-pick one component of QF costs without regard for the overall accuracy of the company's approach.

Staff and ICNU argue that PacifiCorp must perform a burdensome backcast analysis to verify the accuracy of its Generation and Regulation Initiative Decision Tools model (GRID), even though the 2016 variance between the company's actual

NPC and the NPC included in rates was the lowest since 2008. A backcast analysis will provide little insight into the historical variances between forecast and actual NPC. Furthermore, the evidence demonstrates that the GRID model, together with the refinements approved by the Commission, produces a reasonable and accurate NPC forecast.

Finally, Calpine again argues for changes to PacifiCorp's direct access programs, which the Commission has repeatedly rejected. First, Calpine recommends that direct access customers receive the current value (instead of the net present value of a future benefit) of Renewable Energy Credits (REC) (either through a credit or direct transfer or retirement). Calpine's position ignores the Commission's finding in the 2017 TAM that remaining customers receive little or no current value when a REC is freed-up by direct access. Second, Calpine again argues that the Consumer Opt-Out Charge should be reduced to account for accumulated depreciation—without acknowledging that the Commission has now three times rejected the premise underlying this argument. The record here supports the Commission's previous findings that Consumer Opt-Out Charge is necessary to prevent unwarranted cost-shifting.

REPLY UPDATE

Q. In the initial filing, PacifiCorp requested NPC of $380.4 million for the test period ending December 31, 2018. How has your NPC recommendation changed?

A. Test period NPC decreased from $380.4 million to $370.2 million, a $10.2 million reduction from the initial filing. On a total-company basis, NPC decreased by

$41.4 million, from $1.546 billion to $1.504 billion.

Exhibit PAC/401 shows that the company's reply update proposes a rate increase of $7.9 million, or 0.6 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. Exhibit PAC/404 presents updated information for Other Revenue 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) available when the company prepared the update, dated June 23, 2017, and short-term firm transactions; (2) new power, fuel, and transportation/transmission contracts and updates to existing contracts; and (3) a modestly adjusted EIM benefits forecast methodology, based on additional operational experience, to more accurately account for the anticipated growth in EIM benefits in 2018.

Second, as described in further detail later in my testimony, PacifiCorp accepts ICNU's correction to the DA/RT adjustment, CUB's proposed collar for the DA/RT adjustment, and, for this case only, CUB's and Staff's proposal to model Jim Bridger Units 3 and 4 at the minimum levels that existed before the selective catalytic reduction systems (SCR) installation.

Q. Is PacifiCorp'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 2018 NPC and sets a reasonable and realistic NPC baseline for 2018.

Q. Please summarize the major changes in NPC resulting from the reply update.

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

Figure 1
Net Power Cost Reconciliation

	($ millions)	**$/MWh**
OR TAM 2018	**$1,546**	**$26.26**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	($17)	
Purchased Power Expense	$5	
Coal Fuel Expense	($29)	
Natural Gas Fuel Expense	($1)	
Wheeling and Other Expense	$0.1	
Total Increase/(Decrease) to NPC	**($41)**	
OR TAM 2018 July Update	**$1,504**	**$25.56**

The changes in the components of total-company NPC from the initial filing are largely driven by a decrease in the forward market prices for electricity and natural gas. While lower electricity prices reduce wholesale sales revenues, this effect is largely offset by reductions in coal fuel expense and natural gas fuel expense. Purchase power expense is higher due to increased market purchases. Finally, wheeling expense is slightly higher as a result of wheeling expense updates.

Q. Please identify the corrections included in PacifiCorp's reply update.

A. PacifiCorp included one correction in its reply update. The formula the company used to calculate the DA/RT historical average for the period of January 2016 through

June 2016 referred to the market prices from the prior month.[2] The correction reduced NPC by $260,000.

Q. Please explain the updates included in PacifiCorp's reply update.

A. PacifiCorp's reply update includes the following updates:

- **Wheeling Updates—**PacifiCorp allowed two of its long-term transmission rights reservations associated with the Cholla plant to expire, effective May 1, 2018, and September 1, 2018, respectively. Also, Arizona Public Service Company (APS) has released updated tariff rates that will be effective in June 2017. The Company signed two agreements with the Bonneville Power Administration to secure 12 MW of transmission rights in the central Oregon area. These updates increase NPC by approximately $39,000.
- **Mid-Columbia Hydro Updates—**Douglas Public Utility District provided updated project costs for the fiscal year September 1, 2017, through August 31, 2018, in its preliminary pro-forma published on May 3, 2017. This update decreases NPC by approximately $56.
- **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 decreases NPC by approximately $180,000.
- **West Valley Tolling Agreement—**PacifiCorp executed a tolling agreement with Utah Municipal Power Agency for a 185 MW natural gas-fired resource located near West Valley City, Utah. The tolling agreement runs from July 1,

[2] *See* ICNU/100, Mullins/9.

2017, through June 30, 2018. This agreement offers PacifiCorp the option to release reserves held on economic resources, avoid day-ahead energy purchases, and incrementally increase the import and export capability in the EIM. This update decreases NPC by approximately $580,000.

- **QF Contracts Status—**PacifiCorp executed a new QF contract for the output of Brigham Young University – Idaho's cogeneration facility. The company also adjusted the start date of 19 small QF projects, which were reflected in the initial filing, to match the scheduled commercial operation date defined in the contracts, and terminated four of these contracts: Ivory Pine Solar, Beatty Solar, Sprague River Solar, and Wasatch Integrated Waste Management. This update decreases NPC by approximately $790,000.
- **OFPC and Short-Term Firm Transactions—**PacifiCorp updated the OFPC from December 31, 2016, to June 23, 2017. On average, market prices for electricity at the Mid-Columbia (Mid-C) and Palo Verde markets decreased by approximately six percent. Similarly, market prices for natural gas decreased, on average, approximately eight percent. Short-term sales and purchase transactions for electricity and natural gas were also updated through June 1, 2017. These updates decrease NPC by approximately $4 million.
- **EIM Inter-Regional Transfer Benefit—**PacifiCorp's initial filing reflected EIM inter-regional benefits based on the historical average of twelve months ending December 2016. The company has updated its benefit calculation based on additional operational experience and in response to Staff's concern that the initial filing under-forecasted EIM benefits. The company has refined

its methodology, as explained by Ms. Brown. The updated EIM inter-regional benefits increases the EIM benefits in the case by $10.8 million, to a total of $35 million, on a total-company basis.

- **EIM Regulation Reserve Benefit—**PacifiCorp updated the EIM flexibility reserve credit inputs to reflect actual results for January through May 2017 with the expanded EIM footprint. The company's reserve savings increased from 89 MW to 94 MW as a result of this change. Based on updated coal and natural gas prices, however, the cost of holding reserves has decreased; therefore, this update decreases the EIM benefits by approximately $500.
- **Hermiston Pipeline Expense—**Transportation costs to supply natural gas to the Hermiston plant are reduced from historical levels due to the expiration of components of the gas supply and transportation agreements for the plant. This change reduced NPC by $820,000.
- **Coal Costs—**PacifiCorp updated coal costs to reflect changes in prices and volumes. Mr. Ralston provides additional detail on the update in his reply testimony. The update reduces NPC by approximately $2.1 million.
- **Production Tax Credits (PTC)—**The Internal Revenue Service issued a notice[3] on May 26, 2017, updating the PTC rate to 2.4 cents per kilowatt-hour. The updates results in a decrease of $0.7 million to the TAM.

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

A. Staff and CUB argue that because the fixed costs of the SCRs at Jim Bridger Units 3

[3] PAC/406 (Notice 2017-33, 2017-22 IRB 1256, 05/26/2017, IRC Sec(s). 45).

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.[4] CUB proposed a similar adjustment in the 2017 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 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 PacifiCorp willing to agree to CUB's and Staff's adjustment on a non-precedential basis?

A. Yes. Like the 2017 TAM, 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. Accepting this adjustment reduces NPC by approximately $180,000.

REPLY TESTIMONY

Day-Ahead and Real-Time System Balancing Transactions

Introduction

Q. Please briefly describe the DA/RT adjustment the Commission approved for the first time in docket UE 296 and affirmed in docket UE 307.

A. PacifiCorp's adjustment for system balancing transactions has two components. First, to better reflect the market prices available to the company when it transacts in

[4] CUB/100, Jenks/2-3; Staff/200, Kaufman/25.

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 day-ahead and real-time purchases and sales compared to the monthly average market prices. Second, the company also reflects additional transaction volume to account for the use of monthly, daily, and hourly products.

PacifiCorp first proposed the DA/RT adjustment in the 2016 TAM. Over objections from Staff, CUB, and ICNU in that case, the Commission approved the adjustment because it "will result in a more accurate estimate of net power costs."[5]

In the 2017 TAM, Staff, CUB, and ICNU renewed their objections to the DA/RT adjustment. The Commission again affirmed the DA/RT adjustment, concluding that it "reasonably addresses a deficiency of the GRID model and is likely to more fully capture PacifiCorp's net variable power costs."[6]

Q. Have Staff, CUB, and ICNU again objected to the DA/RT adjustment in this case?

A. Yes. Despite Commission approval of the DA/RT adjustment in the 2016 and 2017 TAMs, and despite the undisputed evidence that the NPC forecast with the adjustment is more accurate than without, Staff, CUB, and ICNU have once again asked the Commission to reject the adjustment.

Q. Have the parties raised any new arguments?

A. No. Although the parties propose new modifications to the DA/RT adjustment, the

[5] *In the Matter of PacifiCorp d/b/a Pacific Power's 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 4 (Dec. 11, 2015).
[6] *In the Matter of PacifiCorp d/b/a Pacific Power's 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 13 (Dec. 20, 2016).

proposals rely largely on the same arguments that have now been rejected twice by the Commission. For example, Staff again argues that the DA/RT adjustment is arbitrary and irrational, that it is not a "real model," and has "almost no relationship with market prices, market transactions, or other power cost inputs."[7] As Staff acknowledges, it made these same arguments last year and the Commission disagreed. Staff makes no attempt to reconcile its continued insistence on the irrationality of the DA/RT adjustment with the fact that the Commission has now twice affirmed the adjustment.

Q. As a preliminary matter, Staff contends that PacifiCorp has not produced "compelling evidence to Staff" that the DA/RT adjustment is "calculating a real cost that is incremental to the costs included in GRID."[8] Is this true?

A. No. The Commission has twice found that PacifiCorp presented precisely the compelling evidence Staff claims is lacking. By this point, the company has provided roughly 90 pages of testimony related to this adjustment, including testimony from an outside expert in docket UE 296, the Commission has held two hearings that included cross examination related to the DA/RT adjustment, the company has responded to multiple data requests related to the DA/RT adjustment, and convened a series of technical workshops. Staff has no basis to claim that the Commission's well-reasoned decisions approving the DA/RT adjustment are based on insufficient evidence.

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[7] Staff/200, Kaufman/11.
[8] Staff/200, Kaufman/14.

Response to Staff

Q. What is Staff's recommendation regarding the DA/RT adjustment?

A. Staff recommends two modifications to the DA/RT adjustment. First, Staff recommends that the adjustment be modified so that there is only one monthly price that is correlated with PacifiCorp's retail load.[9] Staff did not quantify the NPC impact of this recommendation.

Second, Staff recommends that the adjustment be modified to account for the value of arbitrage transactions and the residual value of monthly and daily purchase contracts.[10] Staff originally estimated that its recommendation to account for the value of arbitrage transactions would reduce the Company's NPC by $3.1 million; however, in response to a PacifiCorp data request, Staff refined the adjustment to $3.2 million.[11] Staff has not quantified the NPC impact of its proposal to account for the residual value of monthly and daily purchase contracts.

Q. Do Staff's recommendations have merit?

A. No. Staff's first recommendation to modify the forward price curve is the same recommendation Staff made last year.[12] Like last year, Staff has not provided any analysis demonstrating how this proposal would work or demonstrating that its recommendation would produce a more accurate NPC forecast. Staff's recommendation this year also ignores PacifiCorp's testimony in the 2017 TAM that, while implementing more realistic hourly prices could improve the representation of market prices in GRID, it cannot capture the impact of uncertainty in the company's

[9] Staff/200, Kaufman/19.
[10] Staff/200, Kaufman/19.
[11] PAC/408 (Confidential Staff Response to PacifiCorp Data Request 4).
[12] *See, e.g.*, Docket No. UE 307, Staff/200, Kaufman/13.

position and market prices between a day-ahead and hour-ahead time frame. In addition, an hourly price curve cannot capture the necessity of transacting for block products on a day-ahead basis, rather than for products that perfectly align with the company's position.

Staff's second recommendation also relies on previously rejected arguments and flawed analysis, which I discuss below. When Staff's analysis is corrected, it demonstrates exactly why the DA/RT adjustment is necessary.

Q. Staff claims that the DA/RT adjustment introduces error into the NPC forecast because it "reduce[s] the price spread across market hubs for every hour and every hub," and thus "reduces the ability for GRID to make economic cross-hub arbitrage transactions below the ability that the Company has in actual operations."[13] Is this correct?

A. No. Staff made a similar claim in the 2017 TAM.[14] As the Commission described, "Staff explains that, with [DA/RT], PacifiCorp increases the price of the buying hub above forecast and decrease[s] the price of the selling hub below forecast," and that this adjustment "eliminate[s] the value of arbitrage transactions."[15] The Commission rejected Staff's argument in Order No. 16-482, noting that, "PacifiCorp responds that the adjustment properly includes arbitrage transactions[.]"[16] Staff's claim in the 2017 TAM focused on arbitrage transactions at the same delivery point, rather than

[13] Staff/200, Kaufman/12.
[14] Docket No. UE 307, Staff/200, Kaufman/13 ("Staff is concerned that the cost increase may include the cost of arbitrage and hedging transactions and other potentially revenue producing events whose benefits may not be accounted for.").
[15] Order No. 16-482 at 12.
[16] *Id.*

cross-hub arbitrage transactions. But the same deficiencies in Staff's analysis apply here.

Q. Please describe the economic cross-hub arbitrage transactions that Staff claims are reduced because of the DA/RT adjustment.

A. An economic cross-hub arbitrage transaction is a simultaneous transaction to realize the spread between market hubs as a way to monetize available transmission. For example, if the Mid-C price is $20 per megawatt-hour (MWh) and the California-Oregon border (COB) price is $25 per MWh, and there is available transmission between the market hubs, then the Company would purchase at Mid-C and sell at COB, thus realizing a value for available transmission. This opportunity to monetize available transmission is what Staff is referring to as economic cross-hub arbitrage transactions.

Q. Does the DA/RT adjustment properly account for the full value of arbitrage transactions?

A. Yes. All arbitrage transactions, whether at the same delivery point or cross-hub, are purposefully included in the historical data used to calculate the DA/RT adjustment so that the benefits are reflected in the adjustment. This reduces the cost of system balancing transactions and is realistic because it reflects the historical availability of such opportunities.

Q. Has Staff provided any additional analysis demonstrating that the DA/RT adjustment should be modified to reflect economic cross-hub arbitrage transactions?

A. No. Staff provides two examples purporting to show that cross-hub arbitrage transactions are not accounted for.[17] But neither of Staff's examples offer an accurate analysis of the DA/RT adjustment.

Q. Please explain Staff's first example purporting to demonstrate that the DA/RT adjustment does not properly model cross-hub arbitrage transactions.

A. In the first example, which is also the basis for its $3.2 million adjustment, Staff claims that in 2016, after accounting for cross-hub transactions, PacifiCorp realized an average sales price of [redacted] per MWh, or [redacted] the average market price. Staff claims that this shows that the company sells energy for greater than the average market price, which is contrary to the assumption underlying the DA/RT adjustment.

Q. How is Staff's analysis flawed?

A. Staff improperly calculated the value associated with cross-hub arbitrage transactions and thus inflated the average sales price. To account for cross-hub transactions Staff simply aggregated all purchase transactions for the year and then aggregated all sales transactions for the year and netted the two together—without regard for the timing of the transactions. As discussed above, an arbitrage transaction requires a simultaneous purchase and sale. But Staff's calculation effectively assumes that all purchases were used to supply sales without regard to time. For example, assume that PacifiCorp purchased 25 MWh on April 4th at 8:00 am for $20 per MWh (for a total purchase price of $500). Then, assume that on July 7th at 6:00 pm, the Company sold 50 MWh for $75 per MWh (for a total sales price of $3,750). Staff's analysis would label this

[17] Staff/200, Kaufman/15-16.

as a cross-hub transaction with an average sales price of $130 per MWh.[18] But these transactions are not cross-hub arbitrage transactions.

Q. Please describe Staff's second example purporting to demonstrate that the DA/RT adjustment does not properly model cross-hub arbitrage transactions.

A. In the second example, Staff uses two transactions from June 10, 2016, to claim that the DA/RT adjustment does not account for cross-hub arbitrage transactions.[19] The following table is taken from Staff's testimony:

Figure 2

June 10, 2016 Consecutive Market Transactions

	MWh	Cost	$/MWh	Average $/MWh	Dart Adjustment
Mid C Purchase	800	$13,400	$16.75	$14.58	$1,738
COB Sale	(800)	(15,200)	$19.00	$19.51	$407
Net		**(1,800)**			**$2,145**

Staff claims that these two transactions produced a profit of $1,800, which should decrease NPC. But Staff claims that because of the DA/RT adjustment, these two transactions actually increase NPC by $2,145.

Q. How is Staff's analysis flawed?

A. Staff's example is incomplete because it does not examine how these transactions would be modeled without the DA/RT adjustment, which would result in GRID overstating the benefit of the economic cross-hub arbitrage transactions. With the DA/RT adjustment, the forecasted NPC equals the actual benefits calculated by Staff.

[18] In this example, the Company would have earned a net revenue of $3,250 for the net sale of 25 MWh, or $130 per MWh.
[19] Staff/200, Kaufman/16.

Q. Without the DA/RT adjustment, how would GRID model these two transactions?

A. The following table illustrates how these two transactions would be modeled with and without the DA/RT adjustment. Columns A through D and F contain the same data as Staff's example, and column E has been added to show the spread between the actual price and the monthly average price used to calculate the DA/RT adjustment.

Figure 3

	A MWh	B Cost	C Actual Price \$/MWh (A / B)	D Monthly Average Price \$/MWh	E Spread between Actual and Monthly Price (C-D)	F Dart Adjustment (A x E)	G NPC per GRID w/o DA/RT (A x D)	H NPC with DA/RT (G + F)
Mid C Purchase	800	\$ 13,400	\$ 16.75	\$ 14.58	\$ 2.17	\$ 1,738	\$ 11,662	\$ 13,400
COB Sale	(800)	\$ (15,200)	\$ 19.00	\$ 19.51	\$ (0.51)	\$ 407	\$ (15,607)	\$ (15,200)
Total		**\$ (1,800)**				**\$ 2,145**	**\$ (3,945)**	**\$ (1,800)**

As Staff correctly points out, the transactions produce a net benefit of \$1,800 and the DA/RT adjustment resulting from these two transactions is a net cost of \$2,145. But the \$2,145 cost does not directly replace the \$1,800 benefit, as Staff claims; rather, the \$2,145 cost reduces the net benefits of the transactions as they would have been modeled in GRID absent the DA/RT adjustment.

Without the DA/RT adjustment, GRID will realize the spread in Column D, not the actual spread that was realized in Column C, because GRID uses the monthly average price. Therefore, without the DA/RT adjustment, GRID will forecast a benefit of \$3,945 (Column G), which is \$2,145 greater than the actual benefit. Thus, GRID, together with the DA/RT adjustment, reflect the actual cost of the economic cross-hub transactions (Column H). Put another way, Staff's example shows that without the DA/RT adjustment, the value of these arbitrage transactions would be 219 percent higher in GRID than the actual benefits.

Q. Staff further claims that the DA/RT adjustment is the "equivalent of single-issue ratemaking" because it focuses on only one component of historical NPC.[20] Is this a new argument?

A. No. Like Staff's arbitrage claim, this argument is also identical to an argument that Staff made and the Commission rejected in the 2017 TAM.[21]

Q. Staff also claims that the DA/RT adjustment fails to account for the residual value of monthly contracts.[22] Is this true?

A. No. Staff again provides an example purporting to show the flaws in the DA/RT adjustment.[23] But, like Staff's arbitrage example above, this example also fails to recognize how GRID would balance the system.

Q. What is the example provided by Staff?

A. Staff's example assumes the following:

1. PacifiCorp buys a monthly product with 10,000 MWh valued at $20 per MWh for a total of $200,000.
2. PacifiCorp sells 5,000 MWh in daily products priced at $10 per MWh, for a total revenue of $50,000.
3. PacifiCorp keeps the remaining 5,000 MWh in daily products which are valued at $30 per MWh, for a total value of $150,000.[24]

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[20] Staff/200, Kaufman/15.
[21] Docket No. UE 307, Staff/200, Kaufman/12 ("Staff is concerned that the DA-RT model changes do not account for the other moving parts with actual power costs because both adjustments are unrealistic and arbitrary.").
[22] Staff/200, Kaufman/16.
[23] Staff/200, Kaufman/18.
[24] Staff/200, Kaufman/18.

Staff claims that the DA/RT adjustment is flawed because it only accounts for the cost, or selling at a price below the monthly average, associated with the second transaction, and ignores the $30 per MWh book value of the energy that PacifiCorp does not actually sell. To remedy this perceived deficiency, Staff recommends that the DA/RT adjustment be modified to account for part three of its example.[25]

Q. Does Staff's example provide additional support for the DA/RT adjustment?

A. Yes. Staff's example shows exactly why the adjustment to the monthly average price included in the DA/RT adjustment is necessary. In Staff's example, PacifiCorp buys the monthly product and then sells the unused energy as a daily product to keep its system in balance and realize customer benefits. In GRID, however, the model uses only the monthly average price to balance the system, can transact in any increment, and has prefect foresight to its need. Thus, GRID would simply buy the 5,000 MWh from part three, but would do so at the monthly price of $20 per MWh in part one. Without the DA/RT adjustment, GRID would determine a total cost of $100,000 for the 5,000 MWh used to balance the system. As set forth above, however, the true cost of the 5,000 MWh used to balance the system is $150,000, and therefore the DA/RT adjustment is necessary to reflect the actual costs.

The DA/RT adjustment accounts for the spread between the monthly market price in part one ($20 per MWh) and the daily price in part two ($10 per MWh) multiplied by the quantity of the transaction in part two (5,000 MWh) for a total adjustment of $50,000. The unadjusted GRID costs of $100,000 plus the DA/RT adjustment of $50,000 equals the actual cost.

[25] Staff/200, Kaufman/19.

Additionally, this example justifies the need for the volume component of the DA/RT adjustment. Without the DA/RT adjustment, GRID would execute a single transaction to buy 5,000 MWh; whereas in reality PacifiCorp actually buys 10,000 MWh on a monthly basis and then sell 5,000 on a daily basis.

Response to ICNU

Q. What is ICNU's recommendation regarding the DA/RT adjustment?

A. ICNU argues that the DA/RT adjustment improperly accounts for only transactions made less than seven days prior to delivery.[26] ICNU claims that PacifiCorp relies on longer-term transactions to balance its system and that those longer-term transactions must be considered when determining whether the company's total system balancing efforts are imposing a cost. To remedy this alleged deficiency, ICNU recommends expanding the DA/RT adjustment to account for more transactions that have delivery times greater than one week. ICNU's recommendation produces a DA/RT adjustment of $1.0 million, a reduction of $5.9 million.

Q. Is ICNU's recommendation here inconsistent with its prior position on the DA/RT adjustment?

A. Yes. Transactions with delivery periods of greater than one week include a hedging component. Thus, ICNU is now recommending that the DA/RT adjustment include hedging transactions. This position, however, is the exact opposite position ICNU took in the 2016 TAM (docket UE 296), where ICNU argued that the DA/RT adjustment improperly accounted for forward hedging contracts.[27] ICNU's testimony

[26] ICNU/100, Mullins/10.
[27] Docket No. UE 296, ICNU/100, Mullins/7-8; *id*. at 12 ("In other words, the Company's proposals would result in including historical gains or losses from forward contracts in rates, a result that I disagree with.").

fails to reconcile its opposite positions or make any reference to its previous position that the DA/RT adjustment must not include hedging transactions.

Q. Has the Commission ever addressed this issue?

A. Not explicitly, although the Commission rejected all of ICNU's arguments in opposition to the DA/RT adjustment in the 2016 TAM. In the 2017 TAM, the Commission noted that PacifiCorp's testimony indicated that the DA/RT adjustment "properly . . . excludes hedging transactions," and then affirmed the adjustment.[28]

Q. Why has PacifiCorp limited the DA/RT adjustment to only those transactions that occur within seven days of the settlement period?

A. PacifiCorp limited the calculation of its adjustment to transactions with a delivery period of less than one week because those transactions are necessary to balance the Company's system and cannot be postponed. The adjustment is purposely designed to exclude transactions that have hedging components and that is why the adjustment examines only transactions with a delivery period of less than one week.

Q. Is there any merit to ICNU's recommendation to expand the DA/RT adjustment to include transactions with longer delivery times?

A. No. The greater-than-seven-day transactions are included in GRID at their executed price as the transactions become known and therefore do not need to be included in the DA/RT adjustment. For example, the reply update includes 493,200 MWh of short-term firm purchases at Mid-C for the months of January through March. These short-term firm transactions will be updated again in the indicative filing and final update and are included based on their actual cost and volumes. The 2017 TAM

[28] Order No. 16-482 at 12-13.

included approximately 5.1 million MWh of short term-firm sales and 1.8 million MWh of short-term firm purchases across all months—transactions where the volumes and prices were known before the final update and do not need to be modeled in the DA/RT adjustment.

As noted above, GRID performs a single balancing step with perfect knowledge of a single set of prices, loads, and resources and the prices in GRID are the monthly average price based on the OFPC. In a forward market (*i.e.*, the greater-than-seven-day transactions), PacifiCorp will transact at a price that may end up being lower or higher than the actual monthly average price. This spread is the difference between the forward price at the point in time when the company executes the transaction and the spot price at the point in time when the energy is delivered. The DA/RT adjustment is not designed to capture that price spread. Instead, the DA/RT adjustment reflects the fact that in the day-ahead and real-time markets, on average, prices are relatively higher in hours when the company is buying, and lower in hours when the company is selling. Including greater-than-seven-day transactions in the DA/RT adjustment is essentially truing-up the OFPC used in GRID to the historical monthly average price.

Q. ICNU also argues that the DA/RT adjustment varies significantly from year-to-year and therefore the costs captured by the adjustment are impossible to accurately forecast.[29] How do you respond?

A. The fact that a particular component of NPC is difficult to forecast does mean that it should be ignored. As PacifiCorp has shown, and the Commission has found, the

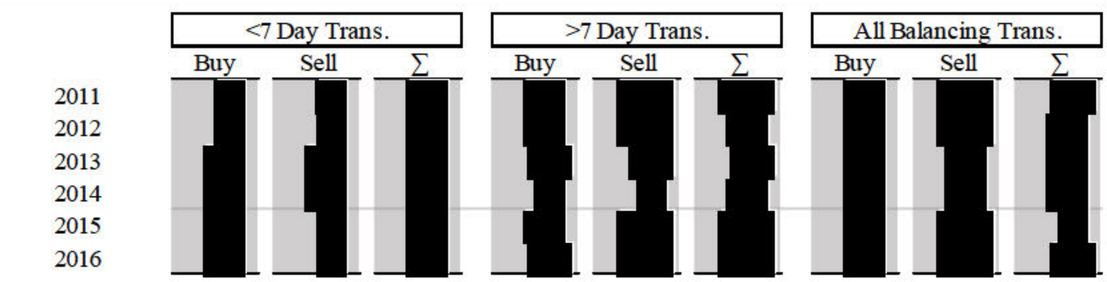
[29] ICNU/100, Mullins/12.

DA/RT adjustment represents costs that are actually incurred and not otherwise accounted for in the NPC forecast. Simply ignoring them will not create a more accurate forecast.

Q. Were there any errors in the analysis ICNU used to claim that the DA/RT adjustment is unreasonably volatile from year-to-year?

A. Yes, in calculating the impact of the greater-than-seven-day transactions, ICNU used an incorrect market price beginning with July 2016.[30] A corrected version of ICNU Confidential Table 2 can be seen below.

Confidential Figure 4
Impact of > 7 Day Transactions on DA/RT Adjustment
Cost/(Benefit) over monthly market price, $millions



Average Annual:	<7 Day Buy	<7 Day Sell	<7 Day Σ	>7 Day Buy	>7 Day Sell	>7 Day Σ	All Buy	All Sell	All Σ
2011-2016	17.2	7.7	24.9	13.5	(18.9)	(5.3)	30.7	(11.2)	19.5
7/2011 - 6/2016	18.9	8.8	27.7 (a)	16.9	(18.3)	(1.4)	35.8	(9.6)	26.3
2015-2016	18.9	4.4	23.3	9.3	(31.2)	(21.8)	28.2	(26.8)	1.4 (b)

(a) Company Proposed DA/RT adjustment with error correction
(b) Corrected ICNU proposed DA/RT adjustment

Q. Do you agree that the corrected information set forth in the table above demonstrates that the DA/RT adjustment should be rejected?

A. No. Contrary to ICNU's conclusion, the table actually supports the need for the DA/RT adjustment. The table shows that with less-than-seven-day transactions (the

[30] This error is shown in Excel row 75 on the Historic Prices tab of Confidential Exhibit ICNU/104.

day-ahead and real-time transactions), the Company consistently purchases above the monthly average price and sells below the monthly average price.

Q. ICNU also claims that data from 2016 indicates that PacifiCorp's DA/RT adjustment overstated the price for short-term purchases and that this fact undermines the rationale behind the DA/RT adjustment.[31] Is this correct?

A. No. Regarding purchases, the DA/RT adjustment captures the difference between the average monthly price and the average purchase price and accounts for the undisputed fact that the Company typically purchases at a price that is greater than the average monthly price. The fact that the forecasted short-term purchase price was greater than the actual short-term purchase price has no bearing on the rationale for the DA/RT adjustment.

Q. Was the variance between the forecast and actual short-term purchase price as great as ICNU claims?

A. No. ICNU relies on its side-by-side analysis that compared the NPC forecast approved in the 2016 TAM to the actual 2016 NPC. ICNU's comparison is flawed, and an accurate comparison of the 2016 NPC forecast and 2016 actual NPC does not support ICNU's claim.

First, when calculating the short-term firm purchases unit cost in the 2016 TAM forecast, ICNU included renewable generation integration charges and EIM import benefits. Removing these items decreases the unit cost of short-term firm purchases in the 2016 TAM from [redacted] per MWh to [redacted] per MWh.

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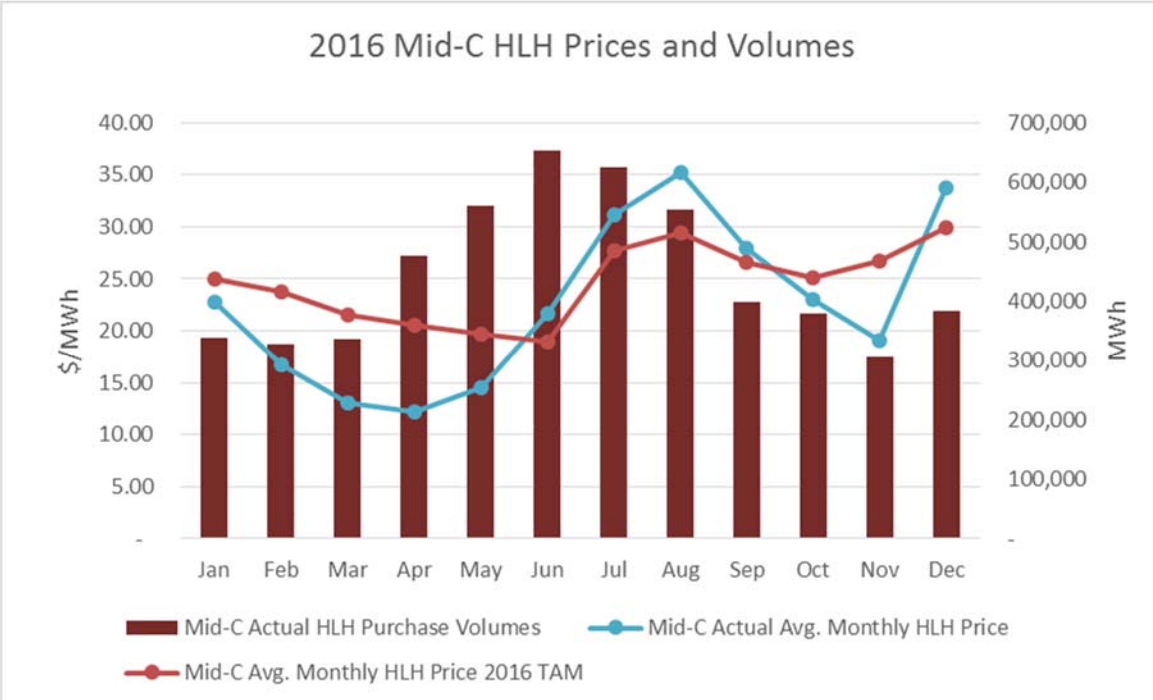
[31] ICNU/100, Mullins/7-8.

Second, when calculating the short-term firm purchases unit cost in the 2016 actual NPC, ICNU included EIM settlements and other firm purchases. EIM settlements are simply the accounting invoice received from the California Independent System Operator. Excluding the EIM settlements and other firm purchases increases the unit cost of short-term firm purchases in the 2016 actual NPC from [redacted] per MWh to [redacted] per MWh. These two corrections reduce ICNU's variance between the forecast and actual short-term purchase prices by roughly 50 percent.

Q. What accounts for the difference between the forecasted and actual unit costs for short-term firm purchases?

A. The difference reflects the fact that, on average, the 2016 monthly electric market price was 7.6 percent lower than the monthly electric market prices used in the 2016 TAM. Further, the actual market prices during the months with particularly high volumes were even lower than the TAM forecasted prices. For example, more than half of PacifiCorp's purchases in 2016 were made at the Mid-C market, and the variance between the actual monthly average high load hour (HLH) price and the 2016 TAM price for April and May was -70 and -35 percent, respectively. These months were also high-volume months for purchases at Mid-C, as shown in Figure 5 below.

Figure 5



This data indicates that the actual short-term purchase price for 2016 was less than the forecasted short-term purchase price because actual market prices were lower. The comparison, however, says little about the merits of the DA/RT adjustment.

Q. ICNU also contends that PacifiCorp's participation in the EIM fundamentally changed how it operates its system and therefore the DA/RT adjustment should be calculated using only data since 2015.[32] Is this a reasonable recommendation?

A. No. This is the same argument CUB made last year, which was rejected by the Commission.[33] Moreover, the use of only two years of historical data to calculate the adjustment runs the risk of creating a non-normalized result. Due the concerns raised by parties, including ICNU in the 2016 TAM, the Company has agreed to use

[32] ICNU/100, Mullins/12-13.
[33] Order No. 16-482 at 12-13.

60 months of historical data to calculate the adjustment. The Commission has found that this is sufficient to create a normalized result.[34]

Q. Has PacifiCorp's participation in the EIM fundamentally changed how it balances its system, as ICNU claims?

A. No. As PacifiCorp described last year when CUB made the same claim, the company's participation in the EIM has not reduced the company's need to incur the system balancing costs captured by the adjustment. The system balancing transaction costs in calendar year 2015, the first full year of EIM data, were actually higher than the 48-month average. Participation in the EIM requires PacifiCorp to submit balanced base schedules 55 minutes before 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 PacifiCorp'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 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,

[34] *See, e.g.*, Order No. 16-482 at 13.

knowing that even if PacifiCorp does not accept, they can sell to other counterparties closer to their 20-minute transmission scheduling deadline.

Response to CUB

Q. What is CUB's recommendation regarding the DA/RT adjustment?

A. As in previous cases, CUB contends that the DA/RT adjustment includes non-normalized costs in the TAM.[35] To address this concern, CUB recommends that the historical average used to calculate the DA/RT adjustment exclude any year in which the forecast NPC varies from actual NPC enough to trigger a power cost adjustment mechanism (PCAM) adjustment. CUB did not quantify the impact of its adjustment.

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

A. PacifiCorp accepts CUB's proposal to exclude DA/RT costs incurred during a year in which an adjustment was triggered in the PCAM when calculating the DA/RT adjustment. The company understands that this collar would be equally applied to years in which the PCAM resulted in either a surcharge or a surcredit.

Coal Plant Dispatch

Q. Staff recommends that PacifiCorp refine its modeling of coal plant dispatch to incorporate additional long-term economic shutdowns.[36] Please describe Staff's adjustment.

A. Staff reviewed the company's GRID model to identify periods with low coal generation, then identified coal units with high fuel costs per MWh, and then manually selected continuous blocks of time to shut down the identified units. Staff's

[35] CUB/100, Jenks/12-13.
[36] Staff/200, Kaufman/21.

adjustment relies on a 60-day shutdown of the Jim Bridger Unit 1 and a 60-day shutdown of Cholla Unit 4, which Staff calculates will reduce PacifiCorp's filed NPC by $0.81 million, though this is impacted by updates to coal prices and market prices. Based on the updated coal and market prices, Staff's adjustment reduces NPC by $0.76 million.

Q. How did Staff identify periods of low coal generation and high fuel costs?

A. According to Staff's response to a PacifiCorp data request, the periods of low coal generation and high fuel costs were intuitive.[37]

Q. Has PacifiCorp shut down coal plants for economic purposes in the past?

A. Yes. PacifiCorp was able to shut down certain coal plants for economic purposes in the second quarter of both 2016 and 2017. In 2016, certain coal plants were displaced by historically low natural gas prices, which allowed greater dispatch of gas plants instead of coal plants. In 2017, a limited number of coal plants were displaced by above normal hydro conditions in the Northwest and California, mild loads, and a surplus of solar energy.

Q. How does Staff's proposed economic shutdown of coal plants differ from PacifiCorp's historical practices?

A. In both of Staff's shutdown scenarios, the coal generation is displaced by market transactions. The pie charts below show the source of the replacement energy in both of Staff's scenarios. Confidential Figure 6 includes only Jim Bridger Unit 1 on economic shutdown, and Confidential Figure 7 reflects both Jim Bridger Unit 1 and Cholla Unit 4 on economic shutdown.

[37] PAC/409 (Staff Response to PacifiCorp Data Request 5).

Confidential Figure 6

[redacted]

Confidential Figure 7

[redacted]

In both scenarios over 80 percent of the replacement energy is provided by the market, a combination of more purchases and fewer sales, which occurs in GRID because the model performs a single balancing step with perfect knowledge of prices, loads, and resources and can transact in any increment. PacifiCorp could not, however, realize this benefit in actual operations because it would not be economic to shut down a coal plant and plan to replace the energy primarily with market transactions. In reality, to displace a coal plant with market transactions the company would have to transact in 25 MW blocks in the HLH or low load hour (LLH) periods and this would force the company to have higher trade volumes in the day-ahead and real-time markets to balance the system, which would increase the DA/RT costs.

Q. Does PacifiCorp have any other concerns with Staff's methodology for modeling economic shutdown of coal plants?

A. Yes. The "intuitive" nature of Staff's methodology[38] is a concern because it does not consider operational needs, including participation in EIM, reliability, minimum take coal contracts, and changes in average coal costs. For example, for reliability purposes, the Company tries to avoid having more than one Jim Bridger unit offline at the same time. During April and May, when Staff's adjustment assumes Jim Bridger Unit 1 is offline, Jim Bridger Unit 3 is also on a 20-day maintenance schedule starting in the middle of May. Additionally, Cholla Unit 4 must come back online by May 15 to serve the APS Exchange, which is not accounted for in Staff's adjustment.

Q. How does PacifiCorp currently model economic shutdowns?

A. As Staff describes, GRID does not model full shutdown of coal plants. Instead, the GRID model will operate coal plants at their minimum capacity when they are uneconomic to dispatch. In actual operations, the Company has shut down coal

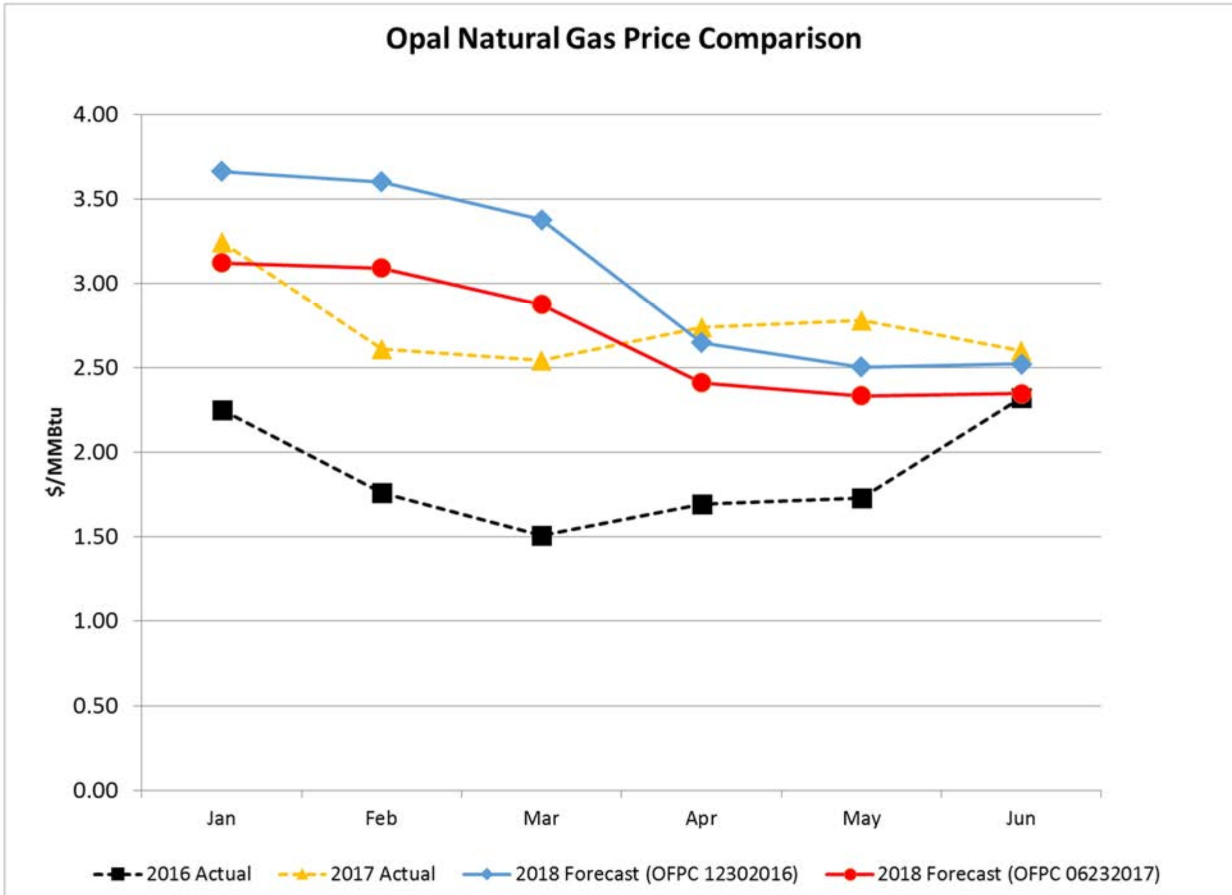
[38] *Id.*

plants for very short periods of time due to economics. The Company has 24 coal plants/units, running all year, which is about eight thousand online days. The economic shutdown that occurred in 2016 was slightly less 3 percent of the coal plant online days.

Q. Is there any reason to believe that 2018 will have similar coal plant shutdowns as 2016 and 2017?

A. No. Unlike 2016, natural gas prices in the 2018 TAM are not expected to economically displace coal. The chart below shows a comparison of natural gas prices year-on-year for the months of January through June. As noted, natural gas prices were very low in 2016, which created an opportunity to replace coal-fired generation with a cheaper natural gas resource. Natural gas prices in 2017 and 2018, however, are not at a level where it would be economical to replace coal generation with natural gas generation.

Figure 8



Moreover, in both GRID studies Staff used to support its economic shutdowns, natural gas generation actually decreases, which means that both Jim Bridger Unit 1 and Cholla Unit 4 were being used to hold reserves and now those reserves must be held on another resource.

In addition, the company forecasts a normal hydro year and therefore a significant increase in hydro cannot be used to displace coal as was the case in 2017.

Q. Are there any other reasons to reject Staff's proposed adjustment?

A. Yes. Staff's proposed modeling change would be significant, and PacifiCorp does not believe that is it reasonable to develop the change during the limited time period afforded by the current TAM's procedural schedule.

Q. Sierra Club recommends that PacifiCorp's coal plant dispatch modeling include variable operations and maintenance (O&M) costs.[39] How does the company respond?

A. Including variable O&M cost in the dispatch decisions in GRID will not have a material impact on the model. Historically, these costs have not been included because, according to Federal Energy Regulatory Commission accounting rules, variable O&M is not a fuel expense. Under the TAM Guidelines, however, the Commission has included certain costs and revenues in the TAM, even if they are not traditionally defined as "NPC." If the Commission decides to include variable O&M in GRID, those costs should also be included when NPC is set in the TAM and trued-up in the PCAM. Including variable O&M in the TAM forecast, however, would also require a change to base rates to remove variable O&M expenses and prevent double-recovery. Because of these complexities, the TAM is not the appropriate venue to implement this modeling change.

EIM Benefits

Q. Please describe Staff's proposed adjustment to EIM benefits reflected in the initial filing.

A. Staff is the only party that challenges PacifiCorp's calculation of EIM benefits, and argues that the company's calculation of the inter-regional EIM benefits improperly relies on only historical data and does not build sufficient growth into the benefits that are anticipated for 2018. Staff recommends that the Commission apply a growth rate to the EIM benefits equal to 50 percent of the average monthly growth rate for

[39] Sierra Club/100, Vitolo/19.

inter-regional benefits. The application of Staff's proposed growth rate would increase the inter-regional EIM benefits by 66 percent, or $16.2 million on a total-company basis. Staff then adjusts for available transmission.[40]

Q. Staff states that PacifiCorp "adopted CUB's proposal to calculate the inter-regional benefit based on available transmission."[41] Is this correct?

A. Partially, as explained in PacifiCorp's initial filing, the company did adopt CUB's proposal from prior TAMs but the result was to *not* calculate the inter-regional benefit based on available transmission.[42]

Q. Does PacifiCorp agree with Staff's recommendation?

A. No. PacifiCorp agrees that its historical EIM benefits have increased due to many factors, including the participation of additional participants in the EIM and the company's ability to more efficiently optimize its resources based on its experience with the EIM. Staff's proposed growth rate, however, is not based on any of those factors but is simply half of the average monthly change.

As noted in Ms. Brown's testimony, PacifiCorp has updated its forecast of EIM benefits to better reflect the company's outlook of EIM benefits in 2018. Ms. Brown describes the methodology for forecast EIM benefits and responds to Staff's proposed adjustment.

[40] Staff/100, Gibbens/12.
[41] Staff/100, Gibbens/7.
[42] PAC/100, Wilding 29.

Modeling QF Contracts

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

A. PacifiCorp'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 company reasonably expects the QF to reach commercial operation during the test period and attests to this fact, then 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. This approach was affirmed by the Commission in the 2017 TAM.[43]

Q. How does PacifiCorp determine when a QF is expected to reach commercial operation?

A. PacifiCorp relies on several sources of information to support the expected commercial operational date. First, the scheduled commercial operation date is set forth in the power purchase agreement (PPA) for each project. As part of the negotiations, various milestones are included in the PPA that are documented and support the commercial operation date.

Second, counterparties provide project status updates on a monthly basis that document progress toward milestones and the commercial operation date.

Third, the company monitors the status of the generator interconnection process, which is posted on the publicly available transmission provider's Open Access Same-Time Information System website, to ensure project output can be brought onto PacifiCorp's transmission system consistent with the commercial

[43] Order No. 16-482 at 18.

operation date. Based on the information known to the company when this case was prepared, the company has a commercially reasonable good faith belief that each of the QFs included in the reply update will reach commercial operation before or during the forecast period. PacifiCorp will update the status of these pending PPAs as new information becomes available.

Fourth, in the TAM November update, the Indicative Filing attestation confirms that the company has a "commercially reasonable good faith belief that the new QFs will reach commercial operation during the rate effective period."[44] In docket UE 287, the parties agreed that "PacifiCorp's attestation will be based on the information known to it as of the contract lockdown date, but does not require PacifiCorp to opine regarding the commercial viability of any QF."[45]

Q. Have the parties proposed adjustments to the Company's modeling of QF contracts?

A. Yes. Both Staff and CUB contend that the TAM Guidelines' methodology for forecasting new QF generation has resulted in over-forecasts of new QF generation because new QFs have historically come online later than anticipated. To account for uncertainty in the on-line date for new QFs, Staff recommends that the Commission assume that each QF will have an 80-day delay in their commercial operation date, which corresponds to the average delay for new QFs coming online after PacifiCorp's final update in the 2017 TAM.[46] Applying this delay decreases NPC by $0.1 million.

[44] *In the Matter of PacifiCorp d/b/a Pacific Power's 2015 Transition Adjustment Mechanism*, Docket No. UE 287, Order No. 14-331 at 5 (Oct. 1, 2014).
[45] Docket No. UE 287, Settling Parties/100, Dickman, Ordonez, Garcia, Jenks & Mullins/11 (Aug. 14, 2014).
[46] Staff/300, Anderson/7.

CUB recommends that PacifiCorp apply a Contract Delay Rate (CDR) to new QFs that would be based on the rolling average of the last three years of available data.[47] In the alternative, CUB recommends that PacifiCorp file an annual deferral to track QF costs so that they can be trued-up the following year.[48]

Q. How do you respond to Staff's proposed adjustment?

A. Staff relies too heavily on the number of delayed QFs, without considering the size of the delayed QFs, or the accuracy of the overall forecast of QF generation. In docket UE 307, PacifiCorp provided a comparison of the number of QFs and the volume of energy from QFs forecasted in each TAM and actual results. The company expanded the table here by adding 2016 actuals. As shown in Figure 9 below, on average, the Company's final TAM forecasts have understated both the total count and total volume of QFs generating energy on the Company's system.

Figure 9

	2016	2015	2014	2013	2012	2011	2010	2009	2008
# of QFs forecasted to sell power in TAM	144	116	99	101	89	79	71	66	58
# of QFs that actually sold power	137	120	101	95	98	91	84	83	66
Difference (Actual - Forecast)	(7)	4	2	(6)	9	12	13	17	8
Percentage Difference	-5%	3%	2%	-6%	10%	15%	18%	26%	14%
QF MWh Forecasted	3,691,500	2,476,266	2,435,389	2,438,691	1,912,866	2,724,235	2,861,965	3,221,069	2,395,995
QF MWh Actual	3,513,084	2,306,533	2,564,988	2,341,269	2,227,854	2,683,387	2,678,393	2,979,815	2,959,861
Difference (Actual - Forecast)	(178,415)	(169,733)	129,598	(97,422)	314,988	(40,848)	(183,572)	(241,255)	563,866
Percentage Difference	-5%	-7%	5%	-4%	16%	-1%	-6%	-7%	24%

Q. Has PacifiCorp examined QF delays by size or nameplate capacity?

A. Yes. When PacifiCorp prepared the initial filing, there were 41 QFs that were projected to come online in 2017. Of those 41 QFs, 25 have reached commercial operation (three of which were ahead of schedule) and 16 are currently delayed. Of the total nameplate capacity of the 41 QFs, the company currently expects 895 MW,

[47] CUB/100, Jenks/10.
[48] CUB/100, Jenks/11.

or 84 percent of the total forecast, to be online by the end of 2017. The average delayed days weighted by QFs' nameplate capacity is about 57 days, which is much smaller than the unweighted delayed days, or the "80-days delay" claimed by the Staff.

Figure 10

Average Delayed Days weighted by QF Namplate Capacity

	Average Delayed Days (unweighted)	Average Delayed Days weighted by QF Nameplate Capacity
CY2017 (UE307)	172	94
CY2016 (UE296)	22	21
Average	97	57

Q. Did PacifiCorp make any other refinements when calculating the average QF delay?

A. Yes. In calculating the delay rate, the number of days delayed was limited to the number of days that the QF would have been in rates had it not been delayed. For example, if, in the 2016 TAM, a QF was expected to be online on December 31, 2016, but its actual online date was February 1, 2017, then the QF was delayed one day because it was only erroneously included in rates for one day. In this example, the 2017 TAM would include the correct online date. In other words, the QF would only be in rates when not actually operating for one day.

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

A. PacifiCorp objects to the proposed CDR. CUB has not presented any analysis that its proposal will result in a more accurate forecast of overall QF generation and costs.[49]

[49] PAC/410 (CUB Response to PacifiCorp Data Request 2).

As noted above, PacifiCorp's overall QF generation is understated. By focusing on only one aspect of QF generation, CUB improperly attempts to decrease the NPC forecast without considering the broader consequences of its adjustment.

Q. How does PacifiCorp respond to CUB's alternative recommendation for an annual QF deferral?

A. PacifiCorp would support an annual deferral of all QF costs. Costs associated with purchases from QFs are outside the control of the company because the company is obligated under federal law to purchase energy from QFs. CUB appears to advocate for a deferral of only new QFs, but this is only one part of QF costs. Limiting the annual deferral to only new QFs is arbitrary, particularly given that the company has historically under-forecast total QF generation.

Q. Do you agree with CUB's statement that customers are being significantly overcharged for QFs?[50]

A. No. On an overall basis, PacifiCorp's NPC forecasts have consistently understated NPC—meaning that customers, in total, have consistently paid less than the actual cost of service. CUB cannot simply point to one line item and suggest customers are being overcharged when rates are based on total NPC. As noted above, the forecast 2016 NPC was reasonable when compared to actual 2016 NPC; however, this does not mean that every line item in NPC was forecast with 100 percent accuracy.

Q. What do you recommend regarding inclusion of QF contracts in the 2018 TAM?

A. PacifiCorp's modeling of QFs in this case is consistent with its historical treatment of QF contracts in the TAM under stipulated amendments to the TAM Guidelines. The

[50] CUB/100, Jenks/9.

Company recommends the Commission affirm this methodology. These provisions address the concerns raised by Staff and CUB in a fair and reasonable manner.

Accuracy of PacifiCorp's NPC Forecast

Q. What is the purpose of the TAM?

A. The purpose of the TAM is to capture costs associated with direct access and prevent unwarranted cost shifting.[51] The TAM 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.

Q. Is it important to set the most accurate NPC forecast possible to meet the Commission's goals for the TAM and PacifiCorp's PCAM?

A. Yes. As noted in my direct testimony, in Order No. 16-482, issued in the 2017 TAM, the Commission reiterated the goal of accurate NPC modeling in the TAM:

> PacifiCorp's TAM is an annual filing in which PacifiCorp projects the amount of [NPC] to be reflected in customer rates for the following year, as well as to set transition charges for customers electing to move to direct access. The TAM effectively removes regulatory lag for the company because the forecasts are used to adjust rates. For that reason, the accuracy of the forecasts is of significant importance to setting fair just and reasonable rates. Our goal, therefore, is to achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year.[52]

In addition, the more accurate the NPC forecast is in the TAM, the less likely it is that PacifiCorp will need to adjust rates through a PCAM surcharge or surcredit in 2019.

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[51] *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).
[52] Order No. 16-482 at 2-3.

Q. Is the TAM currently functioning as intended by the Commission?

A. Yes. In the 2016 TAM, PacifiCorp introduced multiple modeling refinements to increase the accuracy of the total NPC forecast. The changes refined the modeling of thermal forced outages, regulation reserves, generation for wind PPAs, avian curtailment, natural gas start-up energy, and system balancing transactions (the DA/RT adjustment). Except for the avian curtailment, the Commission adopted each of PacifiCorp's proposed refinements. Based on the data from 2016, the first year where the NPC forecast included these refinements, these modeling changes substantially increased the accuracy of the forecast. Figure 11 below shows the difference between the NPC collected through rates set in the TAM and the actual NPC before making certain PCAM adjustments. Figure 11 shows that the forecast approved by the Commission in the 2016 TAM, including the modeling refinements approved that year, resulted in the most accurate NPC forecast since 2008, by a substantial margin.

Figure 11
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
2016	347,055,570	347,188,520	132,950

Q. Was the NPC forecast from the 2016 TAM accurate when compared to the actual NPC incurred in 2016?

A. Yes. The actual 2016 per-unit NPC, after adjusting for changes in load, was $25.13 per MWh, compared to the forecast 2016 NPC of $24.99 per MWh—a difference of only 0.58 percent. Based on the one year of evidence available, PacifiCorp's current modeling produces a reasonably accurate forecast of total NPC that the Commission can rely on to approve fair, just, and reasonable rates.

Q. ICNU claims that PacifiCorp's actual NPC in 2016 was lower than the 2016 TAM forecast.[53] Please respond.

A. First, as demonstrated in Figure 11, PacifiCorp's actual NPC was higher than what PacifiCorp collected in rates, which is the comparison used in the PCAM. Second, with respect to ICNU's comparison of the 2016 TAM forecast to 2016 actual NPC, ICNU claims that the forecasted NPC was 3.76 percent higher than the actual NPC.[54] ICNU's comparison, however, fails to adjust for the difference in load, which was the primary driver of the variance between 2016 forecast NPC and 2016 actual NPC. Compared to the 2016 TAM, actual load was down approximately 2,548 gigawatt-hours, a 4.37 percent decrease. As noted above, after adjusting for load, the variance is an under-forecast of a mere $0.14 per MWh, or 0.58 percent.

[53] ICNU/100, Mullins/7.
[54] ICNU/100, Mullins/6.

Q. Staff and ICNU both recommend that PacifiCorp perform additional modeling to help inform the historical differences between PacifiCorp's forecast and actual NPC.[55] Please describe the basis for these recommendations.

A. Staff acknowledges that PacifiCorp has persistently under-recovered its actual NPC since at least 2008. Staff believes that if the company performs a backcast analysis, which involves replicating historical forecasts using actual market and demand inputs, it will help the Commission and the parties identify the source of the historical discrepancy between forecast and actual NPC. Staff is concerned that the company has improperly relied on adjustments outside of GRID to forecast NPC. Staff claims that a backcast analysis will indicate how GRID can be modified to create a more accurate NPC forecast, thereby eliminating the need for outside-the-model adjustments.

ICNU's recommendation is based on a similar concern that the Commission has approved many outside-the-model adjustments and that it would be preferable to internalize these adjustments through modifications to the GRID model. Like Staff, ICNU believes that a backcast analysis will provide the information necessary for the parties to modify GRID and eliminate the adjustments that are made outside the model.[56]

Q. How do you respond to Staff's and ICNU's request for a backcast analysis?

A. First, the company appreciates the parties' recognition that PacifiCorp has historically under-recovered its NPC, and the parties' interest in achieving a more accurate NPC forecast through the GRID model. While PacifiCorp shares the goal of increasing

[55] Staff/200, Kaufman/10; ICNU/100, Mullins/8.
[56] ICNU/100, Mullins/3-4.

NPC forecast accuracy, a backcast analysis will provide little information that could be used to improve the accuracy of the GRID model. The parties' proposed backcast analysis would run GRID using actual historical inputs, *e.g.*, actual market prices and loads, and then compare the GRID run with actual historical inputs to the GRID forecast without historical inputs and actual historical results. GRID, however, is designed to produce a forecast, not a backcast, and therefore is not a reasonable tool to use as a backcast model.

Q. Why isn't GRID a reasonable model for backcast analyses?

A. First, GRID balances the system differently than PacifiCorp's actual operations. As designed, the GRID model perfectly balances each hour to the fraction of a megawatt and does not simulate transacting in the market for standard products. As the company has explained in support of the DA/RT adjustment, in actual operations, the company continually balances its market position—first with monthly products, then with daily products, and finally with hourly products. The products used to balance the company's forward position in the wholesale market are available in flat 25 MW blocks. PacifiCorp's load and resource balance, however, varies continuously each hour in quantities that may vary widely from a flat 25 MW block. To account for the difference between the 25 MW block products and the actual resource balance, the company must rely on the hourly real-time market. At that point, PacifiCorp must transact to maintain a balanced system and, as a result, becomes a price-taker subject to whatever price is available at the time. In a backcast study, PacifiCorp can use actual load, actual thermal plant dispatch, and actual prices as backcast inputs to remove some of the forecast uncertainties. The backcast study, however, will still rely on GRID's system balancing logic and therefore will not provide new and useful information to identify GRID modeling errors related to system balancing.

Second, GRID has perfect foresight of prices, loads, and resources for the entire forecast period. In reality, prices, market depth, loads, and resources are all uncertain and estimates vary at each step in the system balancing process. A backcast analysis will not provide any insight into the extent that GRID's perfect optimization results in the difference between forecast and actual NPC. Indeed, it is likely that GRID does not sufficiently account for the real constraints faced in PacifiCorp's operation, but a backcast will not identify how to improve GRID to better account for real world constraints.

Third, the GRID model forecasts NPC on a normalized basis, adjusted for known and measurable updates. To normalize the forecast, most of the GRID model inputs are calculated using a historical average. For example, GRID relies on 48-month historical averages to calculate the delivered energy from long-term contracts, generation for wind PPAs, planned outages, forced outages, and heat rate coefficients. The use of a historical average to normalize the inputs captures the multi-year variation and better estimates the future, resulting in a forecast that has an equal probability of being over or under actual results. In a backcast study, the model inputs are replaced by actual data from a single year. Thus, the GRID results will reflect the difference due to the use of one-year of actual data versus a historical average, and will therefore not provide any additional information to help improve the model accuracy.

Q. Are there any other concerns about performing a backcast analysis?

A. Yes. A backcast analysis is not an objective exercise that mechanically changes the inputs to GRID and produces a straightforward result that can be compared to actual historical events. Rather, the analysis is subjective because it requires assumptions from the parties performing the analysis.[57] The same types of disputes that arise when using GRID as a forecasting tool will arise when using GRID as a backcasting tool. The Company believes there is greater value understanding GRID's logic by comparing actual results to GRID's forecast.

In addition, a backcast study will be very laborious because actual data is not always in the necessary format or at the necessary level of granularity required to be a GRID input. Even performing a backcast of a single year, as ICNU recommends, will be burdensome—particularly in light of the limited value such a study would provide.

Q. Staff claims that PacifiCorp has not explained why it is opposed to a backcast analysis.[58] Is this true?

A. No. As Staff describes in its testimony, parties discussed a backcast analysis during the workshops that were held after the conclusion of the 2017 TAM.[59] Contrary to Staff's claims, PacifiCorp raised the same concerns discussed above.

[57] *See, e.g.*, ICNU/100, Mullins/5 ("While I agree with many of the parameters, I would probably perform a backcast in a slightly different way.").
[58] Staff/200, Kaufman/8.
[59] Staff/200, Kaufman/9.

Q. Staff further claims that PacifiCorp has no incentive to perform backcast analysis as long as the DA/RT adjustment is included in the NPC forecast.[60] Is this true?

A. No. Staff's argument assumes that the DA/RT adjustment unreasonably increases NPC to produce a less accurate forecast. But there is no evidence to support that assumption. On the contrary, the Commission has now twice concluded that the DA/RT adjustment produces a more accurate NPC forecast and the actual NPC from 2016, discussed above, provides additional verification that the DA/RT adjustment produces a more accurate NPC forecast. The Commission's repeated approval of the DA/RT adjustment has no bearing on the company's objection to backcast studies. A backcast will further prove the necessity of the DA/RT adjustment in NPC forecast.

Q. Are there any current mechanisms in place to check the accuracy of the TAM?

A. Yes. Each year the PCAM compares the NPC collected from Oregon customers in rates set in the TAM to the actual Oregon-allocated NPC. The PCAM variance, however, is subject to an asymmetrical deadband between a $30 million under-collection and a $15 million over-collection, a sharing band where the Company absorbs 10 percent of the variance outside the deadband, and finally an earnings test where there is no pass through of the PCAM variance if the Company is above or below its authorized return on equity by 100 basis points.

Q. What modifications could be made to the PCAM to increase the effectiveness of the TAM?

A. Eliminating the deadband, sharing band, and earnings test in the PCAM would

[60] Staff/200, Kaufman/9.

increase the effectiveness of the TAM in two ways. First, deadbands and a sharing band in a PCAM are oftentimes misinterpreted as an acceptable variance between the actual NPC and forecasted NPC. This is evidenced by the fact that in the 2016 and 2017 TAMs, parties proposed 29 adjustments, all of which decreased NPC, despite the evidence showing significant under-recovery of NPC prior to 2016. In this case, parties have proposed eight adjustments that, collectively, would decrease NPC by approximately $44 million and perpetuate PacifiCorp's chronic NPC under-recovery.

Second, a PCAM that allowed a full pass through of prudently incurred NPC would shift the focus away from disputes over the assumptions used to produce an NPC forecast and instead focus the Commission and parties on the prudence of the Company's actual NPC. Such an approach would prevent repeated litigation over nearly identical issues and adjustments, such as has occurred in the 2016, 2017, and 2018 TAMs. A prudence determination of actual NPC would be based on facts in the PCAM, instead of contested NPC forecast assumptions. A PCAM that allows full recovery of prudent NPC is now the norm in electric utility regulation because it avoids litigation over NPC forecasts and is fair to all parties.

Q. What is your evidence that a PCAM that allows full recovery of prudent NPC is now the industry norm?

A. Only seven states (out of states with non-restructured power markets)—Wyoming, Idaho, Oregon, Washington, Missouri, Montana, and Vermont—have sharing mechanisms built into their respective power cost true-up mechanisms. Of those seven states, only Oregon, Washington, and Wyoming have sharing mechanisms less than 90 percent.[61]

Q. Is PacifiCorp recommending that the Commission modify the PCAM as part of this proceeding?

A. No. PacifiCorp's position in this case is that the adjustments and proposals raised by Staff and intervenors are unwarranted and should be rejected. A PCAM that allows full recovery of prudent NPC, however, is a logical and effective way to respond to many of the issues raised in this case, including the proposal for an NPC backcast, and reduce litigation in the TAM. For this reason, the company would support a separate docket to review the benefits of modifying the PCAM.

Direct Access – REC Obligation

Q. Calpine recommends 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.[62] How does Calpine's recommendation differ from PacifiCorp's?

A. As described in my direct testimony, PacifiCorp has proposed including a REC credit in the transition adjustment calculation that would be calculated as the future value associated with the delay in the timing of PacifiCorp's Renewable Portfolio Standard (RPS) compliance shortfall. This recommendation is directly responsive to the Commission's finding that RECs freed-up by direct access customers may benefit

[61] PAC/407 (NERA, "ECAC Cost Sharing: A Supplement to NERA's Report on Power Cost Adjustments and Act 162 Compliance," filed with the Hawaiian Public Utilities Commission on behalf of Hawaiian Electric Utilities, September 2014,). Subsequent to the issuance of this report, Utah changed its NPC deferral mechanism to eliminate sharing.
[62] Calpine Solutions/100, Higgins/22-23.

"other customers by altering the point in time when PacifiCorp would need to take resource actions to comply with the RPS."[63]

Calpine recommends that direct access customers receive a credit based on current REC values, or, in the alternative, that PacifiCorp transfers RECs to the Electric Service Supplier (ESS) or retire RECs on behalf of the direct access customer.[64]

Q. How do you respond to Calpine's recommendation that PacifiCorp use current REC prices to calculate the REC credit?

A. Calpine's recommendation is contrary to the Commissions' finding in Order No. 16-482, where the Commission found that, "[i]n the near term, we see little or no benefit from a reduction in RPS obligations due to the loss of load from direct access."[65] If there is no current benefit to remaining customers, as the Commission found, then calculating the REC credit based on current REC prices results in impermissible cost-shifting.

PacifiCorp's proposal, on the other hand, correctly calculates the benefits to remaining customers based on the future delay in PacifiCorp's RPS compliance obligation due to freed up RECs. This is the precise benefit the Commission identified in Order No. 16-482 and providing a REC credit based on the company's methodology ensures that remaining customers are unharmed—the credit paid to direct access customers matches the benefit received by remaining customers.

[63] Order No. 16-482 at 22.
[64] Calpine Solutions/100, Higgins/22-23.
[65] Order No. 16-482 at 22.

Q. Calpine argues that if direct access customers are not given a REC credit based on a current price, they will be harmed.[66] Is this a legitimate reason to use current prices to calculate the REC credit?

A. No. Direct access customers are no more harmed by paying for RPS compliance than they are harmed when they pay for PacifiCorp's fixed generation costs and the fixed generation costs of their ESS. In both situations, the Commission has adopted policies to prevent cost-shifting and protect remaining customers, as required by statute.

Q. Did Calpine's testimony address the Commission's findings from the 2017 TAM?

A. No. Calpine simply reiterated the same arguments it has presented in the 2016 and 2017 TAM without reconciling its arguments with the Commission's explicit findings in Order No. 16-482. Thus, Calpine has provided no basis for the Commission to reverse itself this year.

Q. How do you respond to Calpine's alternative recommendation that PacifiCorp transfer RECs to the ESS, or retire RECs on behalf of the direct access customer?

A. Calpine's alternative proposal suffers from the same flaw as its primary proposal, it results in impermissible cost shifting because the departing customer provides "little or no benefit" to remaining customers, and yet receives the full value of a REC. If providing a monetary credit equal to the current value of a REC impermissibly shifts

[66] Calpine Solutions/100, Higgins/22-23.

costs, which was the Commission's finding last year, then transferring the REC in the same year load departs PacifiCorp's system does too.

In addition, the proposal to transfer RECs to the ESS, while seemingly very simple, would be extremely complicated and administratively burdensome to ensure cost of service customers are held harmless from that transfer. The proposal to retire RECs on behalf of the direct access customer is unacceptable because it would require PacifiCorp to effectively demonstrate RPS compliance on behalf of the ESS. The company should not be required to take on this obligation and associated potential liability.

Q. Please explain why transferring RECs to the ESS would be administratively burdensome.

A. The challenge associated with transferring RECs to an ESS is determining *which* RECs to transfer. Theoretically, direct access customers have contributed to their pro rata share of RECs from each of the company's eligible renewable resources. Depending on the banking provisions applicable to each REC, different RECs will have different value to PacifiCorp and its customers from an RPS compliance perspective. Under the current incremental cost methodology, RECs also have varying levels of incremental costs associated with them, which impacts whether or not the company nears the four percent incremental cost cap. It will be administratively burdensome to appropriately identify and determine which RECs to transfer in order to ensure that cost-of-service customers are held harmless from the loss of RECs to direct access customers.

Q. Are there any other reasons why this recommendation is problematic?

A. Yes. By definition, PacifiCorp cannot transfer bundled RECs to an ESS because once transferred that REC is separated from the underlying energy. Under current RPS requirements, ESS's have no obligation to procure both bundled and unbundled RECs. But this requirement will apply to ESS's beginning in 2021, at which time ESS's will be subject to the same 20 percent unbundled REC limitation that currently applies to investor-owned utilities. Any proposal that includes transferring RECs from PacifiCorp to the ESS will therefore be short-term and less durable than PacifiCorp's proposal to transfer the value of the freed-up RECs to direct access customers.

Q. How do you respond to Calpine's suggestion that PacifiCorp retire RECs on behalf of an ESS?

A. This option is also problematic. In contrast to voluntary programs such as Blue Sky, where PacifiCorp offers to retire, on a customer's behalf, RECs that are purchased and tracked separately from RECs used for RPS compliance, ESS's must retire RECs to demonstrate compliance with the state RPS law. ESS's should be required to be fully responsible for management of their RECs and demonstrating compliance with the law through REC retirements. PacifiCorp is not comfortable putting itself in the position of demonstrating RPS compliance to the Commission on behalf of another entity.

Direct Access – Schedule 200 Escalation

Q. Calpine 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.[67] How do you respond?

A. The Commission should once again reject this recommendation, as it did in dockets UE 267, UE 296, and UE 307. PacifiCorp's direct testimony demonstrated that its fixed generation costs, which are reflected in Schedule 200, increase at a rate greater than the conservative inflation adjustment included in the Consumer Opt-Out Charge.[68]

Q. How does the Consumer Opt-Out Charge operate together with Schedule 200?

A. In the first five years after the direct access customer elects to leave, the customer pays the actual Schedule 200 costs, as those costs change during that five-year period. If PacifiCorp adds incremental generation during those five years and those costs flow into Schedule 200, the direct access customer pays those costs. Calpine does not object to this treatment.

The Consumer Opt-Out Charge accounts for forecast Schedule 200 costs for years six through 10. To calculate the Consumer Opt-Out Charge, PacifiCorp first takes the Schedule 200 costs in effect at the time the customer departs and escalates those costs for five years, using an inflation escalator. The departing customer does not pay these escalated Schedule 200 costs (because the customer is paying the actual Schedule 200 costs for the first five years). Calpine does not object to this escalation.

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[67] Calpine Solution/100, Higgins/37
[68] *See* PAC/110.

PacifiCorp then takes the escalated Schedule 200 cost for year five, and escalates that cost through year 10, using an inflation escalator, to develop a forecast of Schedule 200 costs for years six through 10. The Consumer Opt-Out Charge is then calculated by taking the forecast Schedule 200 costs and reducing them back to calculate a levelized payment made in years one through five. Together, through the payment of Schedule 200 and the Consumer Opt-Out Charge, departing customers pay Pacificorp's fixed generation costs for 10 years (offset by the value of freed-up energy).

Q. What is the basis for Calpine's renewed request to reduce the Consumer Opt-Out Charge for years six through 10?

A. Calpine's arguments here are largely the same arguments the Commission has now rejected in three cases. Calpine agrees that customers should pay Schedule 200 costs for the first five years, but then argues that the Commission should modify the Consumer Opt-Out Charge so that the direct access customer pays only a portion of the fixed generation costs after year five, by virtue of Calpine's proposal to freeze the fixed generation costs in year five.

Q. Has Calpine relied on any new evidence in this case?

A. Yes. In this case, Calpine contends that PacifiCorp's historical fixed generation costs, included in my direct testimony, demonstrate that Schedule 200 costs should decrease in years six through 10.[69] But Calpine can only support this contention by freezing the fixed generation costs in year five and excluding all incremental generation costs incurred after year five.

[69] Calpine Solutions/100, Higgins/33-34.

Q. Has the Commission ever determined that fixed generation costs are frozen after year five in the calculation of the Consumer Opt-Out Charge?

A. No. When the Commission approved the Consumer Opt-Out Charge in docket UE 267, it did so after concluding that PacifiCorp had presented unrebutted evidence of transition costs in years six through 10.[70] The Consumer Opt-Out Charge recovers those transition costs, and, together with Schedule 200 in the first five years, results in departing customers paying fixed generation costs for 10 years. Thus, to use Calpine's terminology, under the Consumer Opt-Out Charge the generation assets are frozen in year 10, not five. If the assets are not frozen in year five, there is no basis for Calpine's recommendations.

In short, the Consumer Opt-Out Charge treats fixed generation costs the same in years one through five as years six through 10, which is consistent with the Commission's finding that there are transition costs for 10 years. The current use of an inflation adjustment in the calculation of the Consumer Opt-Out Charge is also supported by the historical evidence that PacifiCorp's fixed generation costs have grown at a rate faster than inflation.

Q. PacifiCorp previously testified that the inflation escalator used for years six through 10 did not account for incremental generation investment. But doesn't your historical fixed generation costs rely on incremental investment to increase year-over-year?

A. No. In years one through five, the direct access customer pays for incremental generation because the customer pays the actual Schedule 200 costs during those

[70] *In the Matter of PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-060 at 7 (Feb. 24, 2016).

years. For years six through 10, the direct access customer does not pay incremental generation, because Schedule 200 is held constant in real terms. The use of an inflation escalator in the Consumer Opt-Out Charge in years one through five is not intended to account for new generation, just as the inflation adjustment in years six through 10 is not intended to account for new generation.

Q. Has Calpine demonstrated that transition costs do not exist in years six through 10?

A. No. Calpine has not challenged the Commission's fundamental conclusion in Order No. 15-060 that transition costs exist through year 10 and that the Consumer Opt-Out Charge is necessary to recover those costs.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 323
Exhibit PAC/401
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

2018 TAM Allocation Reply Filing

July 2017

PacifiCorp
CY 2018 TAM
Reply Update

Line no		ACCT.	Total Company UE-307 CY 2017 - Final Update	Total Company TAM CY 2018 - Initial Filing	Total Company TAM CY 2018 - Reply Update	Factor	Factors CY 2017	Factors CY 2018	Oregon Allocated UE-307 CY 2017 - Final Update	Oregon Allocated TAM CY 2018 - Initial Filing	Oregon Allocated TAM CY 2018 - Reply Update
1	**Sales for Resale**										
2	Existing Firm PPL	447	13,639,161	13,716,061	12,943,578	SG	25.230%	25.741%	3,441,206	3,530,588	3,331,747
3	Existing Firm UPL	447	-	-	-	SG	25.230%	25.741%	-	-	-
4	Post-Merger Firm	447	381,594,587	298,502,974	316,076,447	SG	25.230%	25.741%	96,277,598	76,836,267	81,359,773
5	Non-Firm	447	-	-	-	SE	23.757%	24.186%	-	-	-
6	**Total Sales for Resale**		395,233,748	312,219,035	329,020,026				99,718,804	80,366,854	84,691,520
7											
8	**Purchased Power**										
9	Existing Firm Demand PPL	555	5,136,503	4,615,778	4,880,688	SG	25.230%	25.741%	1,295,957	1,188,126	1,256,315
10	Existing Firm Demand UPL	555	23,760,262	23,985,699	23,836,008	SG	25.230%	25.741%	5,994,794	6,174,048	6,135,516
11	Existing Firm Energy	555	31,398,600	30,611,344	31,165,314	SE	23.757%	24.186%	7,459,433	7,403,812	7,537,798
12	Post-merger Firm	555	623,969,265	556,550,210	560,841,145	SG	25.230%	25.741%	157,429,544	143,259,010	144,363,519
13	Secondary Purchases	555	-	-	-	SE	23.757%	24.186%	-	-	-
14	Other Generation Expense	555	7,516,842	7,833,208	7,729,619	SG	25.230%	25.741%	1,896,524	2,016,310	1,989,645
15	**Total Purchased Power**		691,781,472	623,596,238	628,452,774				174,076,252	160,041,304	161,282,794
16											
17	**Wheeling Expense**										
18	Existing Firm PPL	565	20,923,037	21,399,139	21,571,135	SG	25.230%	25.741%	5,278,953	5,508,253	5,552,526
19	Existing Firm UPL	565	-	-	-	SG	25.230%	25.741%	-	-	-
20	Post-merger Firm	565	116,941,986	119,493,570	119,480,098	SG	25.230%	25.741%	29,504,856	30,758,286	30,754,818
21	Non-Firm	565	7,699,010	6,253,789	6,253,789	SE	23.757%	24.186%	1,829,070	1,512,572	1,512,572
22	**Total Wheeling Expense**		145,564,033	147,146,498	147,305,022				36,612,879	37,779,111	37,819,916
23											
24	**Fuel Expense**										
25	Fuel Consumed - Coal	501	735,897,583	755,958,645	725,557,593	SE	23.757%	24.186%	174,828,765	182,839,909	175,486,960
26	Fuel Consumed - Coal (Cholla)	501	53,338,302	51,489,296	53,022,785	SE	23.757%	24.186%	12,671,695	12,453,457	12,824,354
27	Fuel Consumed - Gas	501	3,089,382	3,609,585	2,729,839	SE	23.757%	24.186%	733,951	873,032	660,252
28	Natural Gas Consumed	547	294,175,127	268,576,421	268,719,047	SE	23.757%	24.186%	69,887,815	64,959,226	64,993,722
29	Simple Cycle Comb. Turbines	547	2,539,772	2,432,420	2,410,466	SE	23.757%	24.186%	603,379	588,317	583,007
30	Steam from Other Sources	503	4,416,891	5,002,321	5,000,414	SE	23.757%	24.186%	1,049,330	1,209,886	1,209,425
31	**Total Fuel Expense**		1,093,457,057	1,087,068,688	1,057,440,143				259,774,935	262,923,827	255,757,720
32											
33	**Net Power Cost (Per GRID)**		1,535,568,814	1,545,592,389	1,504,177,914				370,745,262	380,377,388	370,168,911
34											
35	Oregon Situs NPC Adustments		486,335	615,552	663,764	OR	100.000%	100.000%	486,335	615,552	663,764
36	**Total NPC Net of Adjustments**		1,536,055,148	1,546,207,942	1,504,841,678				371,231,597	380,992,941	370,832,675
37											
38	Non-NPC EIM Costs*		4,586,168	4,619,225	6,232,850	SG	25.230%	25.741%	1,157,106	1,189,013	1,604,369
39	Production Tax Credit (PTC)		(88,116,470)	(63,857,835)	(66,634,263)	SG	25.230%	25.741%	(22,232,082)	(16,437,349)	(17,152,017)
40	**Total TAM Net of Adjustments**		1,452,524,847	1,486,969,332	1,444,440,265				350,156,621	365,744,605	355,285,027
41											
42									Increase Absent Load Change	15,587,984	5,128,406
43											
44								Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-307	$350,156,621		
45								$ Change due to load variance from UE-307 forecast	(3,134,167)		
46								2018 Recovery of NPC (incl. PTC) in Rates	$347,022,454		
47	*EIM Benefits for the 2018 TAM are reflected in net power costs										
48									**Increase Including Load Change**	**18,722,151**	**8,262,573**
49											
50									Add Other Revenue Change	(360,057)	(360,057)
51											
52									**Total TAM Increase**	**18,362,094**	**7,902,516**

Docket No. UE 323
Exhibit PAC/402
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

2018 Results of Updated NPC Study Reply Filing

July 2017

PacifiCorp

_JulyCum ORTAM18 NPC Study

Net Power Cost Analysis

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12 months ended December 2018	01/18-12/18	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	12,943,578	1,329,577	1,041,309	927,962	782,229	1,015,024	965,667	1,171,388	1,314,021	1,124,271	1,003,880	992,969	1,275,281
BPA Wind	2,593,849	288,856	283,292	261,564	192,047	181,765	176,794	109,030	115,486	160,963	172,214	318,702	333,137
Hurricane Sale	10,904	909	909	909	909	909	909	909	909	909	909	909	909
Leaning Juniper Revenue	75,699	5,199	5,169	7,323	4,437	5,501	5,415	9,137	9,210	7,269	6,267	4,858	5,914
UMPA II s45631	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Long Term Firm Sales	15,624,031	1,624,540	1,330,678	1,197,758	979,622	1,203,198	1,148,784	1,290,464	1,439,626	1,293,413	1,183,269	1,317,438	1,615,241
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	1,315,160	444,080	409,920	461,160	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	26,964,680	9,289,850	8,388,840	9,285,990	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	28,279,840	9,733,930	8,798,760	9,747,150	-	-	-	-	-	-	-	-	-
System Balancing Sales													
COB	29,909,803	2,805,855	3,640,857	3,323,343	1,313,057	1,503,039	971,903	1,086,179	2,994,945	3,405,710	2,336,591	2,771,612	3,756,712
Four Corners	58,173,358	4,230,010	3,071,798	2,855,927	3,368,563	3,074,374	3,394,841	5,671,521	9,005,752	7,462,748	5,972,310	5,232,143	4,833,372
Mead	30,013,576	2,853,904	2,667,840	2,027,817	2,171,848	2,049,777	1,803,675	3,216,082	2,869,758	2,685,372	2,459,757	2,392,891	2,814,854
Mid Columbia	21,509,276	3,981,416	579,220	2,295,877	1,903,106	1,308,823	682,030	2,267,533	2,426,795	2,299,437	1,752,170	820,876	1,191,994
Mona	24,165,690	3,166,006	1,797,803	382,716	1,755,426	1,704,597	1,137,161	1,650,409	2,264,219	3,614,142	1,882,452	2,131,907	2,678,852
NOB	2,054,235	-	62,376	10,278	42,233	48,229	502,123	951,562	384,757	-	-	-	52,678
Palo Verde	84,208,722	961,990	1,079,524	729,485	7,568,583	7,599,857	9,134,227	12,066,674	10,984,987	7,829,759	8,352,256	9,039,243	8,862,139
EIM Exports	34,999,827	2,659,422	3,112,376	3,612,912	3,930,653	2,988,108	2,434,953	3,318,350	1,871,794	1,963,206	3,159,413	2,168,703	3,779,937
Trapped Energy	81,667	22,618	1,273	8,595	278	3,021	-	-	-	-	10,297	26,022	9,564
Total System Balancing Sales	285,116,155	20,681,220	16,013,067	15,246,949	22,053,746	20,279,825	20,060,913	30,228,310	32,803,008	29,260,374	25,925,245	24,583,395	27,980,102
Total Special Sales For Resale	329,020,026	32,039,690	26,142,506	26,191,856	23,033,368	21,483,023	21,209,697	31,518,774	34,242,633	30,553,787	27,108,515	25,900,833	29,595,343

PacifiCorp

_JulyCum ORTAM18 NPC Study

Net Power Cost Analysis

12 months ended December 2018	01/18-12/18	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental	957,594	60,639	88,262	-	102,204	120,015	-	203,658	169,313	48,489	64,530	100,485	-
Combine Hills Wind	4,963,441	308,137	435,589	504,456	513,807	448,450	358,694	417,067	352,633	331,757	344,645	422,697	525,509
Deseret Purchase	34,147,664	3,011,755	2,899,714	2,355,071	2,974,408	2,563,591	2,825,020	3,011,755	3,011,755	2,974,408	3,005,531	2,502,902	3,011,755
Douglas PUD Settlement	1,498,889	77,980	34,003	119,937	229,874	238,773	239,389	292,787	266,145	-	-	-	-
Eagle Mountain - UAMPS/UMPA	2,098,801	133,316	118,598	105,394	101,632	118,482	208,917	358,592	339,547	187,523	127,636	119,809	179,354
Gemstate	1,646,736	137,228	137,228	137,228	137,228	137,228	137,228	137,228	137,228	137,228	137,228	137,228	137,228
Hermiston Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Purchase	125,767	10,481	10,481	10,481	10,481	10,481	10,481	10,481	10,481	10,481	10,481	10,481	10,481
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	7,422,510	613,530	665,660	569,420	633,580	601,500	625,560	601,500	601,500	625,560	613,530	649,620	621,550
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	4,936,059	614,972	552,287	529,921	446,629	270,353	232,773	176,342	187,950	254,197	476,265	586,082	608,288
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	20,567,750	2,680,986	2,018,601	2,046,635	1,574,711	1,395,062	1,118,614	812,910	955,925	1,191,051	1,745,262	2,362,356	2,665,636
Top of the World Wind	40,934,883	5,156,986	4,120,104	4,092,158	3,219,550	2,889,845	2,259,847	1,755,339	1,910,275	2,341,764	3,585,589	4,581,862	5,021,564
Tri-State Purchase	9,855,158	771,707	718,118	744,336	734,048	742,271	830,618	1,117,194	1,006,161	931,836	746,402	731,465	781,003
Wolverine Creek Wind	9,708,530	641,290	955,186	1,020,321	1,016,147	704,764	751,103	644,432	613,928	723,732	795,788	924,987	916,852
West Valley Toll	438,763	179,147	76,196	(126,387)	18,475	210,269	81,064	-	-	-	-	-	-
Long Term Firm Purchases Total	166,601,417	16,673,042	15,104,955	14,383,858	13,987,660	12,726,031	11,954,224	11,814,226	11,837,759	12,032,894	13,927,760	15,404,898	16,754,110
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

PacifiCorp

_JulyCum ORTAM18 NPC Study

Net Power Cost Analysis

12 months ended December 2018	01/18-12/18	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Qualifying Facilities													
QF California	6,204,166	677,731	757,642	850,562	1,075,314	1,091,539	842,612	210,042	110,456	95,115	90,698	127,544	274,912
QF Idaho	8,117,852	603,924	567,731	628,255	661,065	761,218	814,013	756,560	671,270	616,648	680,866	651,498	704,804
QF Oregon	49,930,020	3,197,749	3,294,220	4,079,557	4,925,797	5,367,570	5,317,004	4,911,716	4,839,762	4,295,178	3,642,952	2,774,366	3,284,149
QF Utah	9,479,294	667,814	691,981	803,074	832,864	908,989	921,174	861,473	855,292	811,239	779,671	701,035	644,687
QF Washington	303,094	-	-	-	11,725	27,496	48,710	65,017	69,530	56,851	23,763	-	-
QF Wyoming	213,813	22,907	20,234	23,521	17,712	15,902	12,454	14,997	14,437	13,402	14,963	21,356	21,929
Biomass One QF	14,559,531	1,424,065	1,380,530	1,345,317	1,413,434	917,951	895,332	909,656	1,211,439	1,294,241	1,268,029	1,220,309	1,279,230
DCFP QF	180,872	10,242	10,436	13,637	14,698	14,300	14,880	22,663	21,069	14,751	22,954	15,297	5,944
Enterprise Solar I QF	11,680,683	572,517	619,572	889,693	1,017,279	1,270,925	1,347,874	1,536,025	1,377,335	1,149,175	832,798	586,468	481,021
Escalante Solar I QF	11,041,077	523,548	578,192	845,292	978,524	1,174,518	1,263,433	1,437,145	1,327,993	1,080,740	812,187	556,862	462,643
Escalante Solar II QF	10,552,844	500,754	552,944	807,807	935,260	1,122,312	1,207,723	1,373,061	1,268,740	1,032,733	776,197	532,683	442,632
Escalante Solar III QF	10,114,950	486,387	538,722	781,907	906,966	1,088,810	1,169,181	1,323,235	1,225,478	997,432	704,597	487,070	405,165
Evergreen BioPower QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	7,712,118	484,873	755,990	698,988	688,024	443,755	488,992	579,675	583,684	658,553	686,742	793,938	848,903
Foote Creek III Wind QF	1,719,778	178,153	205,651	224,931	156,368	82,669	72,556	85,717	95,619	100,185	166,322	174,784	176,824
Granite Mountain East Solar QF	11,253,754	564,501	631,754	920,461	1,017,045	1,199,904	1,308,040	1,385,653	1,315,669	1,003,185	834,775	594,913	477,856
Granite Mountain West Solar QF	7,453,410	373,799	418,300	610,696	674,907	795,138	865,935	918,896	870,413	663,543	552,433	393,447	315,905
Iron Springs Solar QF	11,559,221	652,373	680,328	922,344	1,045,869	1,172,694	1,335,765	1,397,031	1,376,056	1,032,744	841,820	591,742	510,455
Kennecott Refinery QF	183,564	-	-	14,072	14,795	22,068	19,129	29,387	30,221	15,074	7,577	15,005	16,236
Kennecott Smelter QF	879,946	-	36,989	45,624	34,289	72,438	78,524	149,190	145,988	62,277	46,918	89,768	117,942
Latigo Wind Park QF	9,674,638	1,011,726	917,570	1,126,955	893,263	860,620	745,979	668,253	572,323	612,790	802,754	709,690	752,715
Mountain Wind 1 QF	9,078,413	1,329,340	1,218,056	888,842	668,064	463,982	456,321	432,799	458,122	466,531	702,313	940,079	1,053,964
Mountain Wind 2 QF	13,927,597	1,910,255	1,769,428	1,368,928	1,020,578	708,474	813,837	797,113	752,079	768,486	1,040,163	1,441,482	1,536,775
North Point Wind QF	17,115,861	1,016,108	1,602,194	1,576,938	1,541,516	987,809	1,104,040	1,325,597	1,395,330	1,536,357	1,567,563	1,688,482	1,773,928
Oregon Wind Farm QF	12,272,883	640,653	923,186	1,075,651	1,283,745	1,269,470	1,160,964	1,267,142	1,131,359	924,107	751,860	801,179	1,043,567
Pavant II Solar QF	3,755,477	156,067	193,744	315,421	365,375	402,839	390,312	473,597	464,741	364,556	300,054	182,373	146,398
Pioneer Wind Park I QF	10,643,896	1,307,800	926,029	1,189,660	901,601	709,426	649,524	650,952	683,005	450,187	822,508	1,259,003	1,094,200
Power County North Wind QF	4,833,038	331,843	511,597	477,117	440,438	293,628	282,047	334,070	330,572	344,250	464,852	476,322	546,303
Power County South Wind QF	4,345,262	283,387	469,754	429,497	406,737	253,526	249,538	300,265	312,553	309,708	413,147	436,422	480,727
Spanish Fork Wind 2 QF	2,688,905	213,350	177,087	190,262	148,532	152,091	217,663	284,892	309,218	265,562	235,746	244,010	250,493
Sunnyside QF	29,503,387	2,606,893	2,424,404	2,578,820	1,677,912	2,547,644	2,542,126	2,616,990	2,545,583	2,586,479	2,187,107	2,545,143	2,644,285
Sweetwater Solar QF	513,761	-	-	-	-	-	-	-	-	-	-	307,413	206,348
Tesoro QF	601,269	21,754	60,744	97,300	65,652	77,861	34,274	33,012	34,926	36,823	32,095	46,447	60,380
Three Peaks Solar QF	8,675,658	422,110	483,455	639,551	852,767	888,395	939,458	1,075,211	1,043,941	811,841	691,202	451,445	376,282
Utah Pavant Solar QF	4,696,652	177,569	227,065	384,798	418,462	468,766	526,364	624,328	597,529	472,633	372,489	238,871	187,780
Utah Red Hills Solar QF	11,750,244	494,957	629,307	802,625	1,047,650	1,228,868	1,265,379	1,548,652	1,502,152	1,334,865	828,407	597,709	469,674
Qualifying Facilities Total	318,374,048	22,993,616	24,400,029	27,781,035	28,262,097	28,976,365	29,488,926	30,485,405	29,642,474	26,349,281	24,056,605	22,773,532	23,164,682
Mid-Columbia Contracts													
Douglas - Wells	2,481,983	310,248	310,248	310,248	310,248	310,248	310,248	310,248	310,248	-	-	-	-
Grant Reasonable	(169,519)	(14,127)	(14,127)	(14,127)	(14,127)	(14,127)	(14,127)	(14,127)	(14,127)	(14,127)	(14,127)	(14,127)	(14,127)
Grant Surplus	2,040,298	170,025	170,025	170,025	170,025	170,025	170,025	170,025	170,025	170,025	170,025	170,025	170,025
Mid-Columbia Contracts Total	4,352,763	466,146	466,146	466,146	466,146	466,146	466,146	466,146	466,146	155,898	155,898	155,898	155,898
Total Long Term Firm Purchases	489,328,228	40,132,803	39,971,130	42,631,040	42,715,903	42,168,543	41,909,296	42,765,778	41,946,379	38,538,073	38,140,263	38,334,329	40,074,690

PacifiCorp

_JulyCum ORTAM18 NPC Study

Net Power Cost Analysis

12 months ended December 2018	01/18-12/18	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
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	13,251,340	4,508,410	4,127,400	4,615,530	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	13,251,340	4,508,410	4,127,400	4,615,530	-	-	-	-	-	-	-	-	-
System Balancing Purchases													
COB	17,403,808	235,955	1,132,384	1,405,873	1,869,039	859,163	2,420,315	3,219,979	3,356,037	1,239,451	148,548	797,390	719,674
Four Corners	12,051,702	845,006	1,208,607	1,283,490	932,211	356,930	915,187	1,182,730	1,449,415	1,356,207	913,482	800,910	807,529
Mead	2,662,413	97,202	653,092	111,912	280,062	213,297	75,725	973,518	38,954	47,901	48,262	39,430	83,058
Mid Columbia	52,610,092	3,113,466	1,366,488	3,637,159	6,574,847	8,714,867	3,491,286	7,881,621	5,375,654	3,333,149	3,807,315	2,897,579	2,416,659
Mona	10,533,552	1,456,569	1,331,232	2,110,488	621,643	130,671	283,405	604,275	505,423	525,793	286,478	1,127,789	1,549,786
NOB	4,545,879	1,426	149,543	17,412	60,221	82,474	1,091,733	2,417,202	586,653	2,991	-	5,345	130,880
Palo Verde	12,569,626	567,039	440,422	419,303	920,686	1,102,219	1,282,385	1,398,572	1,500,491	1,217,929	1,090,488	976,238	1,653,853
EIM Imports	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	366,515	-	-	-	3,675	37,860	208,658	-	56,936	-	53,362	5,088	937
Total System Balancing Purchases	112,743,587	6,316,664	6,281,768	8,985,635	11,262,384	11,497,479	9,768,694	17,677,897	12,869,563	7,723,422	6,347,935	6,649,769	7,362,377
Total Purchased Power & Net Inter	620,723,155	51,407,877	50,830,298	56,682,205	54,428,287	54,116,022	52,127,990	60,893,674	55,265,942	46,711,495	44,938,198	45,434,098	47,887,067

PacifiCorp

_JulyCum ORTAM18 NPC Study

Net Power Cost Analysis

12 months ended December 2018	01/18-12/18	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Wheeling & U. of F. Expense													
Firm Wheeling	145,918,314	11,999,565	12,527,886	12,070,076	11,533,032	12,192,355	12,075,404	12,381,068	12,444,120	12,470,205	12,031,511	12,187,239	12,005,854
C&T EIM Admin fee	1,372,457	114,253	114,274	114,352	114,328	114,360	114,349	114,431	114,441	114,446	114,538	114,495	114,190
ST Firm & Non-Firm	14,250	7,545	1,890	-	-	-	118	-	-	-	-	-	4,697
Total Wheeling & U. of F. Expense	147,305,022	12,121,363	12,644,050	12,184,428	11,647,361	12,306,714	12,189,871	12,495,499	12,558,561	12,584,651	12,146,049	12,301,733	12,124,742
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	53,022,785	5,260,259	4,616,158	4,413,343	3,235,350	3,426,956	3,852,718	5,449,508	6,182,552	3,757,701	4,299,062	4,521,194	4,007,985
Colstrip	14,817,920	1,398,120	1,267,500	1,373,137	1,178,317	1,240,989	1,272,025	1,338,844	1,320,051	1,278,824	1,065,025	746,423	1,338,666
Craig	25,192,051	2,401,799	2,112,046	2,115,839	1,648,347	1,457,379	2,014,306	2,348,735	2,143,320	2,248,899	2,258,366	2,169,145	2,273,869
Dave Johnston	60,023,910	4,586,040	4,459,979	4,739,106	5,010,242	5,401,190	5,445,910	5,515,954	5,445,909	5,184,117	4,956,986	4,765,806	4,512,671
Hayden	10,057,563	927,045	816,368	845,918	816,670	1,003,631	811,606	1,023,140	1,108,940	810,453	451,228	632,633	809,931
Hunter	154,206,342	14,493,057	11,787,361	11,276,302	10,724,281	12,641,209	11,420,120	13,429,517	13,846,898	13,164,056	13,072,981	14,152,572	14,197,989
Huntington	111,507,007	11,371,642	10,791,335	10,202,343	7,400,291	6,728,955	7,208,924	9,683,240	10,140,029	8,693,143	8,321,121	9,182,367	11,783,618
Jim Bridger	206,062,261	23,704,950	20,161,410	16,869,458	10,537,123	11,606,808	13,369,761	19,424,204	20,500,253	15,142,352	17,786,458	17,043,733	19,915,751
Naughton	114,669,683	9,488,310	8,967,796	9,760,837	9,115,860	7,896,383	9,741,990	9,556,938	10,305,520	9,687,867	10,367,579	9,950,982	9,829,621
Wyodak	29,020,855	2,459,935	2,462,455	1,996,673	1,698,388	2,383,575	2,597,084	2,651,778	2,450,613	2,665,376	2,448,174	2,552,338	2,654,466
Total Coal Fuel Burn Expense	778,580,378	76,091,157	67,442,408	63,592,957	51,364,869	53,787,075	57,734,444	70,421,858	73,444,083	62,632,788	65,026,979	65,717,193	71,324,568
Gas Fuel Burn Expense													
Chehalis	38,438,195	2,982,202	2,453,568	2,870,811	3,804,548	1,750,092	2,550,251	5,106,207	4,979,955	5,213,124	3,475,162	475,935	2,776,338
Currant Creek	33,185,296	581,209	816,735	176,613	868,717	2,998,671	3,679,355	5,839,165	5,557,575	4,697,924	2,127,699	3,035,632	2,806,000
Gadsby	2,133,014	-	-	-	-	-	-	991,667	1,112,545	28,803	-	-	-
Gadsby CT	1,174,132	2,249	-	-	-	2,129	38,541	378,025	415,793	169,044	101,548	25,883	40,918
Hermiston	28,307,370	2,921,803	2,788,422	2,311,846	1,386,571	386,289	2,254,327	2,538,744	2,543,897	2,571,287	2,725,537	2,708,358	3,170,289
Lake Side 1	58,236,631	5,135,692	2,092,298	690,827	3,050,616	6,005,251	6,177,940	6,885,334	6,884,756	6,413,814	3,374,538	5,042,407	6,483,159
Lake Side 2	61,771,455	6,388,797	3,149,790	2,804,555	4,798,351	4,094,905	5,056,371	6,211,257	6,521,961	5,793,077	6,175,950	5,224,436	5,552,004
Naughton - Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	223,246,092	18,011,953	11,300,812	8,854,652	13,908,804	15,237,337	19,756,785	27,950,400	28,016,483	24,887,074	17,980,434	16,512,651	20,828,708
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	16,890,530	765,933	901,810	1,756,073	1,488,000	1,621,843	1,553,850	1,570,305	1,548,760	1,574,625	1,514,040	1,509,750	1,085,543
Clay Basin Gas Storage	(49,249)	(36,117)	(29,739)	16,608	-	-	-	-	-	-	-	-	-
Pipeline Reservation Fees	33,771,978	2,828,400	2,701,927	2,828,286	2,786,167	2,828,429	2,788,677	2,877,720	2,881,966	2,797,794	2,834,418	2,787,705	2,830,489
Total Gas Fuel Burn Expense	273,859,352	21,570,168	14,874,810	13,455,618	18,182,970	19,687,608	24,099,313	32,398,424	32,447,209	29,259,494	22,328,892	20,810,105	24,744,740
Other Generation													
Blundell	5,000,414	447,758	423,188	442,380	424,562	445,481	401,858	419,329	407,715	388,855	384,520	355,111	459,657
Blundell Bottoming Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-
Integration Charge	7,729,619	661,874	620,662	725,831	681,613	676,312	660,682	617,361	594,016	575,491	614,796	643,426	657,556
Total Other Generation	12,730,033	1,109,632	1,043,850	1,168,211	1,106,175	1,121,793	1,062,540	1,036,690	1,001,731	964,346	999,316	998,536	1,117,213
Net Power Cost	**1,504,177,914**	130,260,507	120,692,910	120,891,562	113,696,294	119,536,189	126,004,461	145,727,371	140,474,893	121,598,987	118,330,921	119,360,833	127,602,986

Docket No. UE 323
Exhibit PAC/403
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

2018 Corrections and Updates Summary Reply Filing

July 2017

Oregon TAM 2018 (April 2017 Initial Filing)	NPC ($) =	1,545,592,389
	$/MWh =	26.26

	Impact ($)	NPC ($)
Corrections		
C01 - DART Calculation	(1,093,047)	
Accepted Adjustments		
A01 - Remove NPC Impact of Jim Bridger 3&4 SCRs	(674,753)	
Updates		
U01 - Wheeling Updates	159,777	
U02 - Mid Columbia Contracts Updates	232	
U03 - Black Hills Contract Updates	(730,333)	
U04 -West Valley Contract	(2,385,141)	
U05 - QF Contract Status	(3,257,202)	
U06 - Official Forward Price Curve and Short Term Firm Transactions	(16,682,389)	
U07 - EIM Benefits	(10,807,640)	
U08 - Pipeline Updates	(3,390,060)	
U09 - Coal Costs	(8,598,202)	
Total Updates =	(47,458,760)	
System balancing impact of all adjustments	6,044,284	
Total Change from April 2017 Update Filing	(41,414,476)	
Oregon TAM 2018 (July 2017 Filing)	**NPC ($) =**	**1,504,177,914**
	$/MWh =	**25.56**

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

2018 Other Revenue Reply Filing

July 2017

PacifiCorp
CY 2018 TAM
Other Revenues - Stand Alone TAM Adjustment
Reply Update

Line no		Total Company UE-307 Final	Total Company CY 2018 Initial	Total Company CY 2018 Reply	Factor	Factors CY 2017	Factors CY 2018	Oregon Allocated UE-307 Final	Oregon Allocated CY 2018 Initial	Oregon Allocated CY 2018 Reply
1	Seattle City Light - Stateline Wind Farm	(9,749,394)	(10,861,266)	(10,861,266)	SG	25.230%	25.741%	(2,459,805)	(2,795,748)	(2,795,748)
2	Non-company owned Foote Creek	(905,359)	(905,486)	(905,486)	SG	25.230%	25.741%	(233,044)	(233,077)	(233,077)
3	BPA South Idaho Exchange	-	-		SG	25.230%	25.741%	-	-	-
4	Little Mountain Steam Revenues	-	-		SG	25.230%	25.741%	-	-	-
5	James River Royalty Offset	-	-		SG	25.230%	25.741%	-	-	-
6								-		
7	Total Other Revenue	(10,654,753)	(11,766,752)	(11,766,752)				(2,692,849)	(3,028,825)	(3,028,825)
8										
9	Decrease (Increase) in Other Revenues Absent Load Change								(335,976)	(335,976)
10										
11	Baseline Other Revenues in Rates							(2,692,849)		
12	$ Change due to load variance from UE 307 CY 2017 forecast							24,081		
13	Other Revenues in Rates using 2018 load forecast							(2,668,768)		
14										
15	**Decrease (Increase) in Other Revenues Including Load Change**								**(360,057)**	**(360,057)**

Docket No. UE 323
Exhibit PAC/405
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

2018 EIM Costs Reply Filing

July 2017

PacifiCorp
Oregon 2018 TAM
EIM Costs
Reply Update - July 11, 2017

$ dollars

	CY 2018 EIM Costs 13 Month Average							
	Total Company			Factor	Factors	Oregon Allocated		
	2017 Final	Initial Filing	Reply Update		CY 2018	2017 Final	Initial Filing	Reply Update
Capital Investment	16,466,551	16,466,551	16,466,551	SG	25.741%	4,154,566	4,238,579	4,238,579
ADIT	(3,447,093)	(2,892,489)	(2,836,797)	SG	25.741%	(869,713)	(744,542)	(730,207)
Depreciation Reserve	(6,643,572)	(9,401,783)	(9,486,178)	SG	25.741%	(1,676,196)	(2,420,069)	(2,441,793)
Net Rate Base	6,375,886	4,172,279	4,143,576			1,608,657	1,073,967	1,066,579
	10.75%	10.75%	10.75%			10.75%	10.75%	10.75%
Pre-Tax Return on Rate Base	$ 685,656	$ 448,683	$ 445,596	SG	25.741%	$ 172,993	$ 115,493	$ 114,699
Operation & Maintenance (Ongoing)	1,532,526	1,554,589	1,798,843	SG	25.741%	386,661	400,160	463,032
Depreciation	2,367,987	2,615,953	2,615,953	SG	25.741%	597,451	673,360	673,360
Total Revenue Requirement	$ 4,586,168	$ 4,619,225	$ 4,860,393			$ 1,157,106	$ 1,189,013	$ 1,251,091
CAISO Fee in net power costs	$ 1,318,331	$ 1,372,457	$ 1,372,457	SG	25.741%	332,619	353,278	353,278
Total EIM Costs	$ 5,904,499	$ 5,991,683	$ 6,232,850			$ 1,489,725	$ 1,542,291	$ 1,604,369

Docket No. UE 323
Exhibit PAC/406
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

Notice 2017-33, 2017-22 IRB 1256, 05/26/2017, IRC Sec(s). 45

July 2017

Notices

Notice 2017-33, 2017-22 IRB 1256, 05/26/2017, IRC Sec(s). 45

Renewable electricity production credits-annual adjustments.

Headnote:

IRS announced calendar year 2017 inflation adjustment factors and reference prices for renewable electricity production and refined coal production credits under **Code Sec. 45;** . But, IRS also noted that credit period for Indian coal production has expired for calendar year 2017.

Reference(s): **¶ 455.01(3); Code Sec. 45;**

Full Text:

This notice publishes the inflation adjustment factor and reference prices for calendar year 2017 for the renewable electricity production credit and the refined coal production credit under section 45 of the Internal Revenue Code. For calendar year 2017, the credit period for Indian coal production has expired. The 2017 inflation adjustment factor and reference prices are used in determining the availability of the credits. The 2017 inflation adjustment factor and reference prices apply to calendar year 2017 sales of kilowatt hours of electricity produced in the United States or a possession thereof from qualified energy resources and to calendar year 2017 sales of refined coal produced in the United States or a possession thereof.

Background

Section 45(a) provides that the renewable electricity production credit for any tax year is an amount equal to the product of 1.5 cents multiplied by the kilowatt hours of specified electricity produced by the taxpayer and sold to an unrelated person during the tax year. This electricity must be produced from qualified energy resources and at a qualified facility during the 10-year period beginning on the date the facility was originally placed in service.

Section 45(b)(1) provides that the amount of the credit determined under section 45(a) is reduced by an amount which bears the same ratio to the amount of the credit as (A) the amount by which the reference price for the calendar year in which the sale occurs exceeds 8 cents, bears to (B) 3 cents. Under section 45(b)(2), the 1.5 cent amount in section 45(a), the 8 cent amount in section 45(b)(1), the $4.375 amount in section 45(e)(8)(A), and, in section 45(e)(8)(B)(i), the reference price of fuel used as feedstock (within the meaning of section 45(c)(7)(A)) in 2002 are each adjusted by multiplying the amount by the inflation adjustment factor for the calendar year in which the sale occurs. If any amount as increased under the preceding sentence is not a multiple of 0.1 cent, the amount is rounded to the nearest multiple of 0.1 cent. In the case of electricity produced in open-loop biomass facilities, small irrigation power facilities, landfill gas facilities, trash facilities, qualified hydropower facilities, and marine and hydrokinetic renewable energy facilities, section 45(b)(4)(A) requires the amount in effect under section 45(a)(1) (before rounding to the nearest 0.1 cent) to be reduced by one-half.

Section 45(b)(5) provides that in the case of any facility using wind to produce electricity, the amount of the credit determined under section 45(a) (determined after the application of section 45(b)(1), (2), and (3) and without regard to section 45(b)(5)) shall be reduced by (A) in the case of any facility the construction of which begins after December 31, 2016, and before January 1, 2018, 20 percent, (B) in the case of any facility the construction of which begins after December 31, 2017, and before January 1, 2019, 40 percent, and (C) in the case of any facility the construction of which begins after December 31, 2018, and before January 1, 2020, 60 percent.

Section 45(c)(1) defines qualified energy resources as wind, closed-loop biomass, open-loop biomass, geothermal energy, small irrigation power, municipal solid waste, qualified hydropower production, and marine and hydrokinetic renewable energy.

Section 45(d)(1) defines a qualified facility using wind to produce electricity as any facility owned by the taxpayer that is originally placed in service after December 31, 1993, and the construction of which begins before January 1, 2020. See section 45(e)(7) for rules relating to the inapplicability of the c dit to electricity sold to utilities under certain contracts. Section 45(d)(2)(A) defines a qualified facility using closed-loop biomass to produce electricity as any facility (i) owned by the taxpayer that is originally placed in service after December 31, 1992, and the construction of which begins before January 1, 2017, or (ii) owned by the taxpayer which before January 1, 2017, is originally placed in service and modified to use closed-loop biomass to co-fire with coal, with other biomass, or with both, but only if the modification is approved under the Biomass Power for Rural Development Programs or is part of a pilot project of the Commodity Credit Corporation as described in 65 Fed. Reg. 63052. For purposes of section 45(d)(2)(A)(ii), a facility shall be treated as modified before January 1, 2017, if the construction of such modification begins before such date. Section 45(d)(2)(C) provides that in the case of a qualified facility described in section 45(d)(2)(A)(ii), (i) the 10-year period referred to in section 45(a) is treated as beginning no earlier than the date of enactment of section 45(d)(2)(C)(i) (October 22, 2004), and (ii) if the owner of the facility is not the producer of the electricity, the person eligible for the credit allowable under section 45(a) is the lessee or the operator of the facility. Section 45(d)(3)(A) defines a qualified facility using open-loop biomass to produce electricity as any facility owned by the taxpayer which (i) in the case of a facility using agricultural livestock waste nutrients, (I) is originally placed in service after the date of enactment of section 45(d)(3)(A)(i)(I) (October 22, 2004) and the construction of which begins before January 1, 2017, and (II) the nameplate capacity rating of which is not less than 150 kilowatts, and (ii) in the case of any other facility, the construction of which begins before January 1, 2017. In the case of any facility described in section 45(d)(3)(A), if the owner of the facility is not the producer of the electricity, section 45(d)(3)(C) provides that the person eligible for the credit allowable under section 45(a) is the lessee or the operator of the facility.

Section 45(d)(4) defines a qualified facility using geothermal energy to produce electricity as any facility owned by the taxpayer which is originally placed in service after the date of enactment of section 45(d)(4) (October 22, 2004) and the construction of which begins before January 1, 2017. A qualified facility using geothermal energy does not include any property described in section 48(a)(3) the basis of which is taken into account by the taxpayer for purposes of determining the energy c dit under section 48.

Section 45(d)(5) defines a qualified facility using small irrigation power to produce electricity as any facility owned by the taxpayer which is originally placed in service after the date of enactment of section 45(d)(5) (October 22, 2004) and before October 3, 2008.

Section 45(d)(6) defines a qualified facility using gas derived from the biodegradation of municipal solid waste to produce electricity as any facility owned by the taxpayer which is originally placed in service after the date of enactment of section 45(d)(6) (October 22, 2004) and the construction of which begins before January 1, 2017.

Section 45(d)(7) defines a qualified facility (other than a facility described in section 45(d)(6)) that burns municipal solid waste to produce electricity as any facility owned by the taxpayer which is originally placed in service after the date of enactment of section 45(d)(7) (October 22, 2004) and the construction of which begins before January 1, 2017. A qualified facility burning municipal solid waste includes a new unit placed in service in connection with a facility placed in service on or before the date of enactment of section 45(d)(7), but only to the extent of the increased amount of electricity produced at the facility by reason of such new unit.

Section 45(d)(8) provides, in the case of a facility that produces refined coal (other than a facility producing steel industry fuel), the term " refined coal production facility" means any facility producing refined coal placed in service after the date of the enactment of the American Jobs Creation Act of 2004 (October 22, 2004) and before January 1, 2012. Section 45(d)(9) defines a qualified facility producing qualified hydroelectric production described in section 45(c)(8) as (i) any facility producing incremental hydropower production, but only to the extent of its incremental hydropower production attributable to efficiency improvements or additions to capacity described in section 45(c)(8)(B) placed in service after the date of enactment of section 45(d)(9)(A)(i) (August 8, 2005) and before January 1, 2017, and (ii) any other facility placed in service after the date of enactment of section 45(d)(9)(A)(ii) (August 8, 2005) and the construction of which begins before January 1, 2017. Section 45(d)(9)(B) provides that, in the case of a qualified facility described in section 45(d)(9)(A), the 10-year period referred to in section 45(a) is treated as beginning on the date the efficiency improvements or additions to capacity are placed in service. Section 45(d)(9)(C) provides that for purposes of section 45(d)(9)(A)(i), an efficiency improvement or addition to capacity is treated as placed in service before January 1, 2017, if the construction of such improvement or addition begins before such date.

Section 45(d)(11) provides in the case of a facility producing electricity from marine and hydrokinetic renewable energy, the term " qualified facility" means any facility owned by the taxpayer which (A) has a nameplate capacity rating of at least 150 kilowatts, and (B) which is originally placed in service on or after the date of the enactment of section 45(d)(11)(B) (October 3, 2008) and the construction of which begins before January 1, 2017. Section 45(e)(8)(A) provides that the refined coal p ducti c dit is an amount equal to $4.375 per ton of qualified refined coal (i) produced by the taxpayer at a refined coal production facility during the 10-year period beginning on the date the facility was originally placed in service, and (ii) sold by the taxpayer (I) to an unrelated person and (II) during the 10-year period and the tax year. Section 45(e)(8)(B) provides that the amount of credit determined under section 45(e)(8)(A) is reduced by an amount which bears the same ratio to the amount of the increase as (i) the amount by which the reference price of fuel used as feedstock (within the meaning of section 45(c)(7)(A)) for the calendar year in which the sale occurs exceeds an amount equal to 1.7 multiplied by the reference price for such fuel in 2002, bears to (ii) $8.75.

Section 45(e)(2)(A) requires the Secretary to determine and publish in the Federal Register each calendar year the inflation adjustment factor and the reference price for the calendar year. The inflation adjustment factor and the reference prices for the 2017 calendar year were published in the Federal Register on April 12, 2017. Section 45(e)(2)(B) defines the inflation adjustment factor for a calendar year as the fraction the numerator of which is the GDP implicit price deflator for the preceding calendar year and the denominator of which is the GDP implicit price deflator for the calendar year 1992. The term " GDP implicit price deflator" means the most recent revision of the implicit price deflator for the gross domestic product as computed and published by the Department of Commerce before March 15 of the calendar year.

Section 45(e)(2)(C) provides that the reference price is the Secretary's determination of the annual average contract price per kilowatt hour of electricity generated from the same qualified energy resource and sold in the previous year in the United States. Only contracts entered into after December 31, 1989, are taken into account.

Under section 45(e)(8)(C), the determination of the reference price for fuel used as feedstock within the meaning of section 45(c)(7)(A) is made according to rules similar to the rules under section 45(e)(2)(C).

Inflation Adjustment Factor And Reference Prices

The inflation adjustment factor for calendar year 2017 for qualified energy resources and refined coal is 1.5792.

The reference price for calendar year 2017 for facilities producing electricity from wind (based upon information provided by the Department of Energy) is 4.55 cents per kilowatt hour. The reference prices for fuel used as feedstock within the meaning of section 45(c)(7)(A), relating to refined coal production (based upon information provided by the Department of Energy) are $31.90 per ton for calendar year 2002 and $51.09 per ton for calendar year 2017. The reference prices for facilities producing electricity from closed-loop biomass, open-loop biomass, geothermal energy, small irrigation power, municipal solid waste, qualified hydropower production, and marine and hydrokinetic energy have not been determined for calendar year 2017.

Phaseout Calculation

Because the 2017 reference price for electricity produced from wind (4.55 cents per kilowatt hour) does not exceed 8 cents multiplied by the inflation adjustment factor (1.5792), the phaseout of the credit provided in section 45(b)(1) does not apply to such electricity sold during calendar year 2017. However, refer to section 45(b)(5) for an additional phaseout of the credit for wind facilities the construction of which begins after December 31, 2016. Because the 2017 reference price of fuel used as feedstock for refined coal ($51.09) does not exceed $85.64 (which is the $31.90 reference price of such fuel in 2002 multiplied by the inflation adjustment factor (1.5792) and 1.7), the phaseout of the credit provided in section 45(e)(8)(B) does not apply to refined coal sold during calendar year 2017. Further, for electricity produced from closed-loop biomass, open-loop biomass, geothermal energy, small irrigation power, municipal solid waste, qualified hydropower production, and marine and hydrokinetic energy, the phaseout of the credit provided in section 45(b)(1) does not apply to such electricity sold during calendar year 2017.

Credit Amount By Qualified Energy Resource And Facility And Refined Coal

As required by section 45(b)(2), the 1.5 cent amount in section 45(a)(1), and the $4.375 amount in section 45(e)(8)(A) are each adjusted by multiplying such amount by the inflation adjustment factor for the calendar year in which the sale occurs. If any amount as increased under the preceding sentence is not a multiple of 0.1 cent, such amount is rounded to the nearest multiple of 0.1 cent. In the case of electricity produced in open-loop biomass facilities, small irrigation power facilities, landfill gas facilities, trash facilities, qualified hydropower facilities, and marine and hydrokinetic renewable energy facilities, section 45(b)(4)(A) requires the amount in effect under section 45(a)(1) (before rounding to the nearest 0.1 cent) to be reduced by one-half. Under the calculation required by section 45(b)(2), the credit for renewable electricity production for calendar year 2017 under section 45(a) is 2.4 cents per kilowatt hour on the sale of electricity produced from the qualified energy resources of wind, closed-loop biomass, and geothermal energy, and 1.2 cents per kilowatt hour on the sale of electricity produced in open-loop biomass facilities, small irrigation power facilities, landfill gas facilities, trash facilities, qualified hydropower facilities, and marine and hydrokinetic energy facilities. Under the calculation required by section 45(b)(2), the credit for refined coal production for calendar year 2017 under section 45(e)(8)(A) is $6.909 per ton on the sale of qualified refined coal.

Drafting And Contact Information

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Docket No. UE 323
Exhibit PAC/407
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

NERA's Report on Power Cost Adjustments and Act 162 Compliance

July 2017

ECAC Cost Sharing

A Supplement to NERA's Report on Power Cost Adjustments and Act 162 Compliance

Hawaiian Electric Company

September 2014

NERA
Economic Consulting

MMC Marsh & McLennan Companies

Table of Contents

I. Introduction and Conclusions

NERA Economic Consulting ("NERA") was retained by Hawaiian Electric Company, Inc. ("Hawaiian Electric") and its affiliates, Hawai'i Electric Light Company ("Hawai'i Electric Light") and Maui Electric Company ("Maui Electric") (collectively, "Hawaiian Electric Companies," "Companies" or "the Utilities"), to evaluate certain proposals made by the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate") and other parties in Docket No. 2013-0141 regarding the Energy Cost Adjustment Clause ("ECAC")[1] and shared savings cost incentives and to address the concerns expressed therein.

In the past, NERA has evaluated the incentives built into the Companies' respective ECACs. NERA performed this evaluation in order to provide an opinion as to whether the terms of the ECACs comply with Act 162. We present our analysis and findings on Act 162 compliance in our *Report on Power Cost Adjustments and Act 162 Compliance*, filed in the Hawaiian Electric 2014 general rate case.

This report supplements our prior report and provides in-depth analyses of the issues raised by the parties in Docket No. 2013-0141. Specifically, the Companies asked us to examine concerns that they do not face proper incentives to control costs. In addition, they asked us to study and report on whether it would be appropriate and beneficial for customers to employ economic incentives and penalties *within the ECAC* to reward efforts to reduce costs, improve service and provide affordable rates. Together the ECAC and the PPAC clauses provide the Companies with the opportunity to fully recover all purchased power costs including the full costs of purchasing renewable capacity and energy. For simplicity, the term "ECAC" is used in this report to refer to the combined ECAC and PPAC.

With respect to suggestions that the Companies do not face proper incentives to control costs, we find such concerns to be without foundation. The presence of regulatory oversight for fuel and purchased power contracts, and the costs and risks of high rates – leading to the prospect of customer bypass – are among the factors that exert pressure on the Companies to control costs.

The effect of these pressures to control costs is highly visible in recent initiatives undertaken by the Companies. Hawaiian Electric has successfully negotiated a contract amendment with an upstream fuel supplier that will reduce the cost of low-sulfur fuel oil by $ 22 million annually; this amendment is currently pending approval by the Commission. In addition, the Companies are actively exploring the use of Liquefied Natural Gas (LNG) as a lower-cost and cleaner alternative to oil and have pro-actively reserved liquefaction capacity in order to be to able to effect those plans. These endeavors invalidate characterizations by other parties that the Companies do not face appropriate incentives to minimize fuel costs.

[1] The ECAC recovers fuel and purchased power energy costs not recovered in base rate energy charges. By contrast, the Purchased Power Adjustment Clause ("PPAC") recovers all non-energy purchased power costs.

Introduction and Conclusions

Our analysis of existing and potential changes to the ECAC incentive structure leads us to the following conclusions:

1. Contrary to the claims of other parties, the ECAC framework that is currently in place for the Hawaiian Electric Companies provides appropriate incentives and does include an incentive mechanism for improved heat rate performance. Modifications could be made to assure that the heat rate targets continue to be appropriate and to avoid situations where they penalize or reward the Hawaiian Electric Companies based on factors outside of their control.
2. Potential changes to the ECAC to incorporate shared fuel market deviations are not in the public interest. Sharing of the risk of oil price fluctuations between customers and shareholders is not proper regulatory policy as the utility has no control over world oil markets. Such sharing is as likely to harm as to help customers and would not be fair to the utility as it would preclude recovery of prudently-incurred costs.
3. The current provisions in the ECAC, which pass through world oil price fluctuations, track prevailing regulatory practice in other states whose utilities face volatile fuel or purchased power costs. In fact, forty-two of fifty states surveyed provide a dollar-for-dollar pass through of market-driven changes in fuel or purchased power costs. In the relatively uncommon cases where fuel market risk is shared between investors and customers, the threat to the financial health of the utility is much less pronounced than it would be in Hawai‘i. In those states, the utilities tend to generate a small share of their energy using oil and gas and the sharing mechanisms pose limited financial risk. This is not the case for Hawai‘i.
4. Exposing the Companies’ financial condition to the vagaries of the world oil prices would put their financial viability at risk, raise the costs of capital and make it difficult for Hawaiian Electric Companies to achieve the financial stability required to invest in projects to reduce oil usage in the long term and fulfill the vision of the Hawai’i Public Utilities Commission (“Commission”) for the future of Hawai’i’s electric utilities.
5. The Consumer Advocate’s concern that the ECAC creates a potential bias in strategic planning in favor of resource plans that result in costs that are ECAC recoverable is unwarranted. The Companies must assess the economics of alternative resource choices, as they face strong incentives to control costs and to stay competitive. The terms of the ECAC do not favor fossil fuel based generation over renewables. Renewables, like fossil fuel plants, flow through the ECAC without discrimination. In this sense, the ECAC is neutral to resource choice.
6. On the issue of strategic planning, the ECAC must be viewed not in isolation but as a part of a comprehensive regulatory structure that includes a business and operational plan and detailed rate case reviews and appropriate cost recovery mechanisms. The incentives provided by the ECAC are appropriate in the context of this comprehensive regulatory structure. In some cases the ECAC is neutral with respect to encouraging specific resources, but such encouragement is accomplished through other means and more appropriately so.

II. Structure of Report

NERA organizes its report as follows:

- In Sections III and IV, we provide an overview of the concerns about incentives voiced by the other parties in Docket No. 2013-0141.
- In Section V, we address general concerns that the Companies do not have incentives to control costs.
- In Sections VI and VII, we present our benchmarking of the ECAC. This allows us to place the current ECAC incentive structure and potential changes thereto in the context of well-established regulatory practice in the United States.
- In Section VIII, we offer an economic framework for evaluating whether specific incentives are likely to be efficient and beneficial for customers.
- In Section IX, we discuss the costs, risks and potential harm from placing world oil price risk on Hawaiian Electric investors.
- In Section X, we address whether the Companies have sufficient incentives to operate and develop renewable resources.
- In Section XI, we consider the Commission's vision for a 21st century power sector in Hawai'i and describe how the ECAC is necessary to facilitate the realization of this vision.

III. Docket No. 2013-0141 – Schedule B

On October 10, 2013, the Public Utilities Commission of the State of Hawai‘i initiated Docket No. 2013-0141 to reexamine whether the decoupling mechanism employed by the Hawaiian Electric Companies is functioning as intended to serve the public interest.[2] In particular, the Commission stated that it would review whether, and to what degree, revenue recovery through a combination of formulaic adjustment mechanisms and traditional rate cases may be appropriate for Hawai‘i to minimize regulatory lag and uncertainty and whether it is appropriate to consider and adopt other innovative methods to ensure timely cost recovery and streamline the ratemaking process to improve regulatory oversight.[3]

The Commission bifurcated its decoupling reexamination investigation into two parts – Schedules A and B – each with its own issues and schedule.[4] Among the issues in Schedule B were whether the Companies current decoupling mechanisms have sufficient incentives for the Companies to control costs and whether potential economic incentives/penalties could be utilized in connection with Senate Bill 120, Session Laws of Hawai‘i 2013.

Senate Bill 120 was passed in early April 2013 and the governor signed it into law as Act 37 on April 22, 2013. Act 37 “authorizes the public utilities commission to establish a policy to implement economic incentives and cost recovery regulatory mechanisms to induce and accelerate electric utilities' cost reduction efforts, encourage greater utilization of renewable energy, accelerate the retirement of utility fossil generation, and increase investments to modernize the State's electrical grids.”[5] It includes provisions for:

- The establishment of a shared cost savings incentive mechanism designed to induce a public utility to reduce energy costs and operating costs and accelerate the implementation of energy cost reduction practices[6];

- The establishment of a renewable energy curtailment mitigation incentive mechanism to encourage public utilities to implement curtailment mitigation practices when lower cost renewable energy is available but not utilized through the sharing of energy cost savings

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[2] The decoupling mechanism consists of the revenue balancing account (“RBA”) and the RAM.

[3] See Order No. 31289, issued May 31, 2013 in Docket No. 2013-0141 (“*Decoupling Reexamination Order*”) initiating an investigation to reexamine the existing decoupling mechanisms for the Hawaiian Electric Companies, at p. 11.

[4] Order No. 31484, as amended by Order No. 31494; Order No. 31635, issued October 28, 2013 in Docket No. 2013-0141.

[5] For additional detail, see http://www.capitol.hawaii.gov/session2013/Bills/SB120_SD1_.HTM.

[6] Shared cost incentives in regulatory practice in the US generally refer to providing the utility with the opportunity to enhance returns by sharing in savings created by actions and investments. Shared savings models sound similar to proposals to share in fuel cost deviations, but actually are quite different.

between the public utility, ratepayer, and affected renewable energy projects;

IV. Positions of Other Parties

In this section, we review positions taken by the parties to the decoupling proceeding. Our overall assessment of these positions is that they conflate elements of Act 37 which reference the concept of shared savings with arguments that it would be appropriate to fix some portion of fuel cost recovery using a pre-defined target and have the Companies and customers "share" in deviations from that target. In fact, the only thing such proposals have in common with shared savings as it utilized in regulatory practice is the word "share." As we explain in the subsequent sections of this report – where we describe the strong incentives the Companies face to control all costs and the widespread use of fuel adjustment clauses – sharing deviations from targets that are of necessity arbitrarily defined and over which the Companies have little or no control is not reasonable regulatory practice and is counter-productive. In this Section, we quote from the positions of the Consumer Advocate and the other parties in order to establish a context for explaining why these positions, which advocate against the pass through of fuel and purchased power costs, are incorrect.

The Consumer Advocate contends in its Statement of Positions:

> "The Consumer Advocate also observes that the RAM mechanism addresses only a fraction of the utility costs ultimately recovered from ratepayers. Much larger amounts of fuel expense, purchased energy costs and purchased power capacity costs are recovered through the ECAC and PPAC with only narrowly defined potential for less than full cost recovery. The favorable cost-recovery treatment afforded changes in these other non-RAM elements of utility cost insulate the utility from otherwise significant risks of non-recovery, creating a potential bias in strategic planning in favor of resource plans that result in costs that are ECAC/PPAC recoverable over plans that result in higher "base" costs that may be more difficult to recover on a timely basis."[7]
>
> "It is possible that a shared savings mechanism could be extended to include energy and PPA costs as well. <u>For example, 90% of energy costs could be recovered via a tracker, while the other 10% could be held constant (or subject to a productivity factor) in order to induce the Companies to reduce dependence on volatile energy costs and pursue lower-cost resources</u>. [Emphasis added.]
>
> The Consumer Advocate cautions, however, that design of such an ECAC incentive mechanism is a complex undertaking that would require extensive analysis and evaluation, and would need to be designed to complement the other incentive

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[7] Before the Public Utilities Commission of the State of Hawaii, In the Matter of Public Utilities Commission Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, Docket No. 2013-0141, Division of Consumer Advocacy's Initial Statement of Position Schedule B Issues, May 20, 2014, pp. 45-6.

> mechanisms in place. The Consumer Advocate believes that such a mechanism may be best investigated in a separate Commission-initiated investigation or future rate cases."[8]

For its part, the Blue Planet Foundation alleges that:

> "[R]egulatory cost recovery mechanisms, such as the Energy Cost Adjustment Clause ("ECAC"), do not provide sufficient economic incentives or penalties... *Id*."[9]

> "As one example, regulation based on the RIIO model can address the disadvantages associated with cost pass-through mechanisms such as the ECAC. Existing pass-through mechanisms, such as the ECAC, may inappropriately shelter utility shareholders from the risks associated with volatile fossil fuel prices."[10]

> "The PPAC may possibly be modified to allow this additional incentive amount or the Commission may possibly leave the PPAC unmodified and allow the collection of this additional amount as a type of decoupling performance metric. Assuming the foregoing constitutes an "incentive," shared cost savings could constitute a modification to the ECAC for utility recovery of fossil fuel costs. For example, the ECAC could be modified to reduce the utility's authorized percentage amount of collection under the ECAC to the extent recovery for fossil fuel costs increases relative to renewable generation over a specified time period."[11]

Hawai'i Solar Energy Association claims:

> "Yet, the utility currently has no "skin in the game" because the ECAC essentially passes through the fuel costs and risks to the customers. *Id.* at 23. A specific PIM should be established accordingly to encourage the HECO Companies to reduce their overall fuel use.

> Act 37 includes a "shared cost savings incentive mechanism" concept, Haw. Rev. Stat. § 269-6(d)(1), which in this context could involve the HECO Companies receiving a portion of the savings from a reduction in their fuel use. It should be noted that a shared savings mechanism based on reductions in overall fuel *costs* would involve inherent complexities. Since fuel costs depend on various factors not all within the HECO

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[8] *Id.*, pp. 51-2.

[9] Before the Public Utilities Commission of the State of Hawaii, In the Matter of Public Utilities Commission Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, Docket No. 2013-0141, Blue Planet Foundation's Initial Statement of Position on Schedule B Issues and Certificate of Service, May 20, 2014, pp. 6-7.

[10] *Id.*, p. 18.

[11] *Id.*, p. 27.

> Companies' control, those costs may not be an accurate gauge of utility performance, and the utility may receive an unjustified windfall if the market price of fuel drops…
>
> At the same time, current circumstances may advise in favor of eliminating the heat rate incentives in the ECAC. These incentives may be encouraging the utility to keep its thermal generating units running at consistently higher levels, rather than operating them more flexibly to allow further renewable energy use and greater efficiencies and cost savings across the entire system."[12]

In summary, with various qualifiers,[13] the other parties all appear to interpret the legislature's initiative to establish various shared savings mechanisms as vehicles for forcing a change and substantial reduction in fossil fuel usage by making it difficult for the Companies to recover the full costs of purchasing the oil required to supply electricity in the Hawaiian Islands given the current infrastructure. In regulatory practice, shared savings mechanisms are not arbitrary measures that impose cost recovery risks in order to discourage the use of an identified input. Rather, such mechanisms are targeted cost recovery mechanisms designed to provide a financial incentive for a utility to take action to reduce costs. They are employed in situations where the utility may not be inclined to take action absent an explicit incentive or where it is necessary to remove a disincentive to pursue a particular cost reducing action. In general, the Division of Consumer Advocacy and the other parties misinterpret shared savings mechanisms and conflate them with the sharing of deviations in costs from arbitrarily defined targets including elements over which the utilities have little or no control.

[12] Before the Public Utilities Commission of the State of Hawaii, In the Matter of Public Utilities Commission Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, Docket No. 2013-0141, Hawai'i Solar Energy Association's Initial Statement of Position on Exhibits "A"-"B" and Certificate of Service, May 20, 2014, p. 17.

[13] The Consumer Advocate recognizes that it will need to be studied in a separate docket. The County of Hawai'i supports the phase-out of such mechanisms over time.

V. Incentives to Control Costs

As discussed in the previous section, some of the parties to the proceeding take issue with the Companies' incentives to control fuel costs under the existing ECAC framework. For example, as noted, HSEA states that the ECAC provides no incentive to control fuel costs[14] and recommends establishment of a specific mechanism to encourage the Companies to reduce overall fuel use. The Consumer Advocate presents a more nuanced claim, arguing that there is no incentive for cost control beyond the fixed heat rate with deadband.[15] In this section, and in Section VIII below, we explain why the claims of the Consumer Advocate and HSEA regarding the Companies' incentives are inaccurate.

Contrary to these claims, we find that the Companies face meaningful incentives to control fuel costs. These incentives result from regulatory oversight and competitive threats unrelated to the ECAC recovery mechanism. The primary regulatory oversight is required Commission approval of the fuel supply agreement. As a practical matter, the Companies negotiate term fuel supply agreements that are tied to world oil prices. These contracts provide for variability in fuel quantities taken to accommodate the difficulties inherent in predicting system dispatch and plant capacity factors. Given the link to world oil prices, there is little room in the fuel purchasing process to achieve pricing that is more favorable than market. In other words, it would be unreasonable to expect that the Companies could procure fuel on an arms-length basis with third party suppliers at a discount to the market price. However, if the Companies fail to negotiate reasonable contract pricing terms reflective of market and appropriate adders for transportation differentials, then they will risk the Commission's disapproval of the fuel supply agreement. The Companies negotiate a reasonable market-priced fuel acquisition arrangement for Commission approval. Actual fuel prices realized within the contract are outside of the Companies' control. The regulatory framework provides an appropriate and meaningful incentive to control fuel costs and obtain reasonable fuel contract pricing terms while recognizing that the Companies are still price-takers in world oil markets.

Independent of the regulatory framework, the Companies face pressures that create incentives to act efficiently and lower fuel usage and other costs. Specifically, the Companies face competitive threats from microgrids and behind-the-meter generation. Such threats are present for all classes of customers, whether it is rooftop solar for small residential or commercial customers or larger-scale self-generation for industrial customers. As the economics of certain

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[14] Before the Public Utilities Commission of the State of Hawaii, In the Matter of Public Utilities Commission Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, Docket No. 2013-0141, Hawai'i Solar Energy Association's Initial Statement of Position on Exhibits "A"-"B" and Certificate of Service, May 20, 2014, p. 7.

[15] Before the Public Utilities Commission of the State of Hawaii, In the Matter of Public Utilities Commission Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, Docket No. 2013-0141, Division of Consumer Advocacy's Initial Statement of Position Schedule B Issues, May 20, 2014, p. 28.

of these competitive alternatives improves – as has been the case in recent years –the Companies face even stronger incentives to control costs and stay competitive. Moreover, as rates rise, consumer satisfaction and regulatory resistance to rate increases will be factors that can negatively affect the returns a utility is able to achieve. Load growth in the service area will also be negatively affected by higher rates. The Companies, like other utilities, have strong long-term incentives to keep costs as low as possible while maintaining reliable service.

The parties generally take the position, explicitly or implicitly, that decoupling insulates the companies from these pressures and that the Companies have little financial incentive to provide electricity at least cost as lower sales will, through the decoupling mechanism, simply result in higher rates and have little or no impact on earnings. They imply or state that the Companies are indifferent to reducing oil usage as they are able to recover oil costs through the ECAC and recover the impact of reduced sales caused by high oil costs through the decoupling mechanism. What these parties fail to recognize is that these phenomena are strictly short term and that it would be irrational for the Companies to consider only the short term. In the longer term, the risks that the Companies face include the following.

1. **Technological Advances -** New lower cost supply or demand technologies may be developed. These may be deployed directly by customers to reduce demand· or to provide on-site supply. They may be deployed by competitors to reduce utility demand. Finally, they may be deployed by the utility. In any case, future technological innovation could make it challenging to recover the full cost of new supply-side investments.

2. **Environmental Regulation -** There is increasing concern for the environmental effects of power generation, transmission and distribution. It is impossible to predict the course of environmental regulation over the long term, but it is conceivable that environmental concerns would render certain investments unusable, would require substantial capital expenditures for others and could result in cost increases which would prevent the utility from fully recovering the cost of new investments associated with load growth.

3. **Competition -** The position of the utility as a monopoly is continually changing. Open access proposals, on-site generation and customer conservation alternatives all pose risks. If utilities build or buy under long-term contracts to meet sales growth, and then load is reduced by competitive alternatives, it will be challenging to fully and fairly recover fixed costs from the remaining customer load. While the Companies may not face competition in the same way that mainland utilities do, they are likely more vulnerable to competition from some types of dispersed resources.

These possibilities provide real and significant incentives that make the promotion of efficiency improvements and cost effective renewables attractive to the Companies. There is no guarantee that the Companies will be able to fully recover investments over the long term if the services they provide are not competitive. The Companies' best way to manage their long-term risks is to strive to minimize costs over the long term. This incentive is a strong additional incentive and is present even in conjunction with a currently prevailing regulatory decoupling mechanism. In summary, the claims and implications that the current regulatory system is devoid of incentives for the utilities to seek to minimize costs are based on a very incomplete analysis focusing only on short-term financial impacts and fail to consider the long-term incentives that the Companies face. These claims are further belied by the Companies efforts to investigate the potential for LNG as a substitute for fuel oil, an investment that would be intended to reduce costs over the long term, the Companies' recent reservation of tariffed liquefaction capacity in British Columbia and the recent amendment to a fuel oil supply contract with Chevron anticipated to provide for $ 22 million in annual fuel cost savings.

Furthermore, as we demonstrate in Sections VIII, IX and XI, no efficiency gains can be achieved by placing an incentive on the Companies when they are simply price takers in a global oil market and doing so would be harmful. This provides further support for maintaining the current ECAC framework in which the Companies receive cost recovery for all prudently-incurred fuel costs and adjustments are made pursuant to a power plant operating performance incentive mechanism.

Before turning to those sections, however, we will briefly add perspective on certain specific items addressed in Act 37. We reiterate those items and provide perspective on each below. This is not done to critique or defend Act 37, but only to illustrate how the "sharing" concepts offered by the Consumer Advocate and the other parties are inconsistent with sound regulatory policy.

- The establishment of a shared cost savings incentive mechanism designed to induce a public utility to reduce energy costs and operating costs and accelerate the implementation of energy cost reduction practices – *shared savings can provide a utility an enhanced short term financial incentive to reduce costs. However, it is not reasonable or productive to apply such mechanisms to factors outside of utility control. A shared saving mechanism applicable to specific incremental actions identified to reduce costs may be a useful addition to the regulatory framework in specific instances. For example, if an investment was identified that led to reduced fuel costs, the investment would not be recoverable until the next rate case while the fuel costs savings would immediately flow through the ECAC, it may be reasonable to provide for a shared savings mechanism that would be in effect until the next rate reset.*

- The establishment of a renewable energy curtailment mitigation incentive mechanism to encourage public utilities to implement curtailment mitigation practices when lower cost renewable energy is available but not utilized through the sharing of energy cost savings between the public utility, ratepayer, and affected renewable energy projects -- *The Companies' operating practice is economic dispatch, which is described in detail in Appendix N "System Operation and Transparency of Operations", to the respective Company Power Supply Improvement Plans. There is little renewable energy curtailment anticipated, as shown in the Conclusions and Recommendations of the Power*

> *Supply Improvement Plans.*[16] *Moreover, minimizing curtailment is not the same as minimizing costs or maximizing renewable volumes overall and a mechanism focused only on minimizing curtailment could provide improper incentives.*

In sum, the suggestions for shared savings mechanisms purported to provide the Companies explicit financial incentives to reduce fuel costs or reduce financial disincentives to do so appear intended to discourage the usage of oil by arbitrarily placing the recovery of oil purchase costs at risk under the guise of "sharing." As explained subsequently herein that is inconsistent with accepted regulatory practice and would lead to adverse outcomes including exposing customers to risk and frustrating the ability of the Companies to implement the Commission view of Hawai'i's energy future.

[16] These plans indicate Maui Electric is to achieve > 95.8% annual renewable utilization, Hawai'i Electric Light >96.1%, and Hawaiian Electric >97.3%.

VI. The ECAC and Regulatory Best Practices

Fuel adjustment clause ("FAC") mechanisms (and other similar cost adjustment and tracking mechanisms) give utilities a reasonable opportunity to recover their legitimate costs of procuring fuel and electricity on behalf of customers. By providing timely cost recovery for fuel and power costs, the amount of time between rate cases can increase and the risk to a utility's financial ability to perform in the event of sudden changes in fuel prices can be mitigated. The breadth of adjustment clauses is not limited to fuel and purchased power expenses. Rather, the ECAC or a similar adjustment mechanism can be implemented efficiently for recovery of other costs that meet the three classic reasons for an automatic rate adjustment. These are:

1. The cost of the purchased resource is outside the control of the utility that purchases it.
2. The item accounts for a significant or large component of the utility's total operating costs.
3. Costs related to the resource are volatile and unpredictable.

Adjustment and cost tracking mechanisms may also be implemented to allow for the parallel treatment of similar cost categories. For example, demand-side management ("DSM") costs provide a substitute for pursuing supply-side resources. If supply-side resources are recovered under a FAC, DSM costs could be treated symmetrically, which would put supply- and demand-side energy costs on an equal footing.

For modern utilities that operate in a world of volatile fuel prices an FAC is critical to:

- Reduce the volatility of utility earnings. Companies exhibiting large earnings volatility are typically those with most difficulty in tracking input costs.

- Provide the utility with a reasonable opportunity to recover its prudently-incurred costs in rates.

- Lower the risks to capital invested in a utility and thus lower the utility's cost of capital (and ultimately, rates) as well as help maintain the utility's credit rating. Volatile wholesale power and oil and gas commodity markets have led the rating agencies to more closely scrutinize cost-recovery mechanisms. Credit rating agencies, for example, recognize the need for robust and frequently updated FAC mechanisms.[17]

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[17] Each of the three major credit rating agencies recognize the importance of FAC mechanisms. *Fitch* states: "[i]n today's environment, the safest bonds in the utility industry may be those of vertically integrated utilities operating under commission-approved mechanisms to recoup prudently incurred power costs. Such companies typically operate in supportive regulatory environments which continue to feel the need for healthy reserve margins of generation."

S&P also notes that "[a]utomatic pass-through mechanisms that hold companies harmless from uncontrollable costs, such as fuel or foreign exchange effects, are viewed favorably."

(…)

- Maintain the Companies' liquidity. Because oil, and other fuel expenses, are a large portion of the Companies' operational costs, the ECAC is needed to enable them to raise capital in a time frame needed to meet expenses and investment requirements.

Utility regulators have long recognized the crucial role that cost recovery mechanisms play in allowing the utility an opportunity to recover its costs. FACs permit a utility to recover its costs and assure the capital markets that the company can meet its obligations to shareholders and bondholders. Colorado provides an example of its commission balancing the concerns of the utility and its customers. The Colorado PUC explained its long-term use of FAC mechanisms by stating that it established its FAC in order to permit rapid recovery of increased costs over which the utility has no control. The PUC recognized that, in the circumstances which existed at the time, unless increased fuel costs were passed through to customers expeditiously, the utility would undergo a serious erosion of earnings jeopardizing its ability to provide service.[18]

When approving the Arizona Public Service Company's ("APS") proposed Power Supply Adjustor, the Arizona Corporation Commission stated "we agree that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating" and that "an adjustor that works correctly, over time, reduces the volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity in a rate case and result in lower rates."[19]

As a frequently updated, fully reconciled pass through mechanism for a large and volatile expense, the ECAC plays a critical role. Continuation of the ECAC allows the Companies to more readily raise capital in the future. This will improve their ability to meet future infrastructure needs and preserve the level of service demanded by their ratepayers and the Commission. Hawaiian Electric recognized this fact stating in the Form 10-K that:

> "Risks, uncertainties and other important factors that could cause actual results to differ materially from those in forward–looking statements and from historical results include, but are not limited to…fuel oil price changes, performance by

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Moody's concludes that: "Regulated vertically integrated utilities operating without regulatory recovery of potentially high electricity costs from spot-market purchases are equally vulnerable, particularly during periods of peak energy demand and/or supply shortages."

See: *Fitch*, "Procuring Power in California: A Potential Stranded Cost," September 7, 2000, p. 4.
Standard & Poor's, "Rating Methodology For Global Power Utilities," Standard & Poor's Infrastructure Finance, September 1998, p. 66.
Moody's, "Credit Implications of Power Supply Risk," July 2000, p. 3.

[18] Before the Public Utilities Commission of the State of Colorado, "In the Investigation of Electric Cost Adjustment Clauses For Regulated Electric Utilities," Docket No. 93I-702E, Decision No. C95-248, February 6, 1995.

[19] Before the Arizona Public Corporation Commission, In the Matter of the Application of Arizona Public Service for Approval of Adjustment Mechanisms, Docket No. E-01345A-02-0403, Decision No. 66567, November 13, 2003, p. 5.

> suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses."[20]

The ECAC that Hawaiian Electric and its affiliates currently have in place is comparable to the FACs that are used by other traditionally regulated jurisdictions in the United States. Nearly all traditionally regulated and most restructured states in the US have some similar mechanism for power cost recovery. Like the ECAC, most of the restructured states with fuel clauses have some form of "true-up" mechanism to reconcile actual and forecasted costs. Many of those states have rate adjustments on a quarterly or more frequent basis. Exhibit 1 contains NERA's survey of FACs in the fifty states and the District of Columbia.

Both fuel costs and purchased energy costs are recovered through the ECAC. A weighted average of the various fuel and purchased energy costs is computed monthly based on an estimated fuel mix. This is then converted to a rate for customers based on the estimated MWh sales for the month. An efficiency factor (MBtu/kWh) is used to calculate the conversion between the MBtu of fuel purchased and the amount of kWhs generated. The ECAC is updated monthly and an Energy Cost Adjustment ("ECA") factor is determined on a prospective basis. A reconciliation is done on a quarterly basis, which compares revenues recovered through the ECAC plus base fuel revenues versus revenues allowed for fuel and purchased energy. Revenue allowed for purchased energy are equal to actual purchased energy costs. Revenues allowed for fuel are determined using calculated sales heat rates,[21] actual fuel MMBTUs, kWh sales, and actual fuel prices. The over-collection or under-collection is adjusted in the ECA factor for the following three months to the extent that actual costs are within a range referred to as the dead band. The monthly ECAC filings with the Commission ensure timely recovery of fuel and purchased energy costs for the Hawaiian Electric Companies and ensure that customers pay no more than prevailing fuel prices.

[20] For additional detail, see https://www.sec.gov/Archives/edgar/data/46207/000035470714000026/he-12312013x10k.htm.

[21] Sales heat rates are calculated by fuel type, taking mbtu of fuel consumed divided by the kWh of sales provided by that fuel type. The calculated sales heat rate is compared to a target heat rate plus or minus a fixed btu/kWh deadband for the fuel type that is established in a rate case. If the calculated sales heat rate is higher than the target heat rate plus the deadband, then the value of the target heat rate plus the deadband is used. If the calculated sales heat rate falls between the target heat rate plus the deadband and the target heat rate minus the deadband, the calculated sales heat rate value is used. If the calculated sales heat rate is lower than the target heat rate minus the deadband, then the value of the target heat rate minus the deadband is used. The determined sales heat rate value is multiplied by sales to calculate the mbtu to be recovered. The mbtu value multiplied by the fuel cost per mbtu determines the total amount to be recovered through base rates and ECAC for that fuel type.

VII. Consistency with Regulatory Practice in Other States

As shown in Exhibit 1, forty-two of fifty states surveyed provide a dollar-for-dollar pass through of market-driven changes in fuel or purchased power costs. As elaborated elsewhere in this report, such policy is appropriate as utilities cannot control the prices in upstream fuel markets and asking them to bear fuel price risks would undermine established regulatory principles (such as the recovery of prudent costs) and would harm customers by placing the utilities' financial integrity at risk and foreclosing opportunities to benefit from near-term fuel price reductions.

NERA did identify eight states in which fuel market risk is shared between investors and customers. In these uncommon cases, the utilities' fuel consumption profile is different from that of the Hawaiian Electric Companies. As a result, the threat to the financial health of the utility is much less pronounced than it would be in Hawai‘i. In those states, the utilities tend to generate a small share of their energy using oil and gas and the sharing mechanisms pose limited financial risk. This is not the case for Hawai‘i.

In each of these states, the sharing mechanisms pose limited financial risk. As Exhibit 2 illustrates, the generation profile in Hawai‘i is distinct from that of the other states relying on fuel market risk sharing. Utilities in the states listed above that rely on coal tend to contract at relatively stable prices and do not face the cost volatility that utilities relying on natural gas or oil face. As such, the implications of the risk sharing arrangements for the utilities' financial integrity are markedly different. Such a mechanism would not be appropriate for in Hawai‘i or in any other state where the utility faces a large quantity of volatile fuel purchases.

VIII. Economic Rationale for Efficiency Provisions in the ECAC

This section provides an economic framework for evaluating the efficiency provisions in the ECAC. Such a framework can be used to consider arguments from the Consumer Advocate and the Blue Planet Foundation that the ECAC does not provide sufficient incentives to control costs.

Efficient risk sharing occurs when the party that has the means to control a cost has an incentive to do so. This distinction is critical because the price of fuel is, realistically, beyond the control of the utility. The Companies act as a price taker in the world-wide market for fuels (*i.e.*, oil) and the design of the ECAC and the recovery of fuel and purchased energy costs should recognize this fact.

Accordingly, the ECAC acts to pass exogenous changes in input costs onto consumers. In fuel markets (as in other markets where the Companies are price takers—as in vehicles), it is straightforward to demonstrate prudent purchasing. There is a well-defined market price and a well-defined need to buy from this market (*i.e.*, ratepayers' demand for electricity). In a price-taking market, "risk sharing" of fuel price changes would lead to no efficiency gains resulting from management incentives to minimize costs. Accordingly, exogenous changes in the price of fuel are not imprudent and should be fully passed onto ratepayers. This provides them with a price signal, which is an incentive to use resources efficiently. This supports the utility's ability to maintain its financial viability, and increases the time between rate cases for costs that are within the utility's control, which enhance the utility's incentive to control its base rate costs.

The ECAC, with its "heat rate" efficiency factor, provides a partial pass through of fuel costs in those areas where the Companies do have managerial control. It shares the risk/benefit of increased plant operating efficiency by tying the Companies' ability to recover their fuel costs (and thus their financial performance) to their power plant performance, while also allowing the Companies to pass through the exogenous changes in the price of an input over which they have no control, the price of fuel, as well as all purchased power energy costs.

The Hawaiian Electric Companies have considerable control over the operation and maintenance of their plants—limited by engineering realities—and therefore it is reasonable, as the Commission already does, to provide the Companies with an incentive to improve their operating efficiency to manage or lower their fuel costs. As discussed in the next section, putting fuel oil expense recovery at risk in an attempt to give the Companies an incentive to integrate non fuel oil resources would be an inefficient, indirect and counterproductive way of changing the resource mix.

This heat rate efficiency factor properly shares the risk of efficiently operating and maintaining the Companies' generating units and recognizes that the added risk of cost recovery associated with plant operation is balanced with rewards from productivity increases. It is proper that the ECAC does not assign the risk and reward of uncontrollable changes in fuel prices to the utility. While the risk to customers is sometimes initially viewed as a risk that prices will rise suddenly with oil price volatility and customers will pay higher prices while the Companies are insulated from the impact of oil price changes, sharp moves can and do occur in both directions. For example, after reaching the mid $100 per barrel level in the summer of 2008, oil prices dropped by $100 per barrel to the $40 per barrel range in the winter of 2008/2009. A timely and responsive ECAC ensures that customers see the benefit of such price declines and that the Companies do not experience a windfall from a decline in the price of an input over which they have no control. The ECAC works to share the risks of oil price volatility symmetrically and in both directions and is fully consistent with the fairness criterion of Act 162. For example in 2009, Hawaiian Electric's low sulfur fuel oil ("LSFO") costs dropped by over $400 million. Absent an ECAC, customers would not have seen the benefits of this drop. Even if the ECAC was for 90% of costs, customers would have missed out on an over $40 million dollar savings.

We understand that the current ECAC does have its limitations in providing a reasonable target benchmark heat rate. This can be attributed to the use of an average heat rate for fuel types when plant operating profiles are difficult to predict as they fluctuate with changing loads on the system and the production of energy from other sources. In this regard, the Hawaiian Electric Companies differ from the utilities in Florida where heat rate targets are also used in the FAC. In Florida, the heat rate incentives apply to base load facilities and are not applied to plants with difficult-to-predict operating profiles. Particularly as renewable penetration increases, the operating patterns of the Companies' generating units will change. Average heat rate is not only a function of how well the plants are maintained, which is under the Companies' control and should be incentivized, but also of the demand that the units face, which is largely outside of the Companies' control and is not well suited to incentives. This is the case because the operation of the plant, including its performance efficiency, is different at different demand levels. Historically, the operating patterns of the Companies' units, while variable, were not wholly unpredictable. As the penetration of intermittent generation increases, the ability to predict operating patterns decreases and heat rate targets set for fuel types used in plants that are intermittently operated can become less meaningful and not reflective of factors under the Companies' control.[22] This creates the potential for either financial harm or windfall gains for the Companies related to factors outside of their control.

As a result of these limitations, refinements to the ECAC will be worth examining, in order to assure that the heat rate targets continue to be appropriate and to avoid situations where they penalize or reward the Hawaiian Electric Companies based on factors outside of their control. For instance, the heat rate target targets could be eliminated and fuel costs could be passed through the ECAC as incurred for fuel types used in plants that have a small, uncertain, and intermittent contribution to generation operations. Or alternatively, target heat rate deadbands could be widened significantly for fuel types used intermittently and/or in small quantities. However, we believe that the consideration and potential implementation of such changes will represent a refinement to an otherwise robust incentive mechanism.

[22] There are provisions to update the heat rate target as renewable development increases and in response to other changes, but these require filing production costs analyses and awaiting a Commission determination and may not always be effective on a timely basis.

IX. The Costs of Sharing Fuel Market Risk

The risk of fuel cost changes is determined by:

1. Changes in the price of fuel as a single productive input; and,
2. Changes in the cost to deliver and produce electricity from the Hawaiian Electric Companies' fuel inputs. This reflects any changes in the technical ability of the utility to turn fuel purchased into electricity, which may require the Companies to purchase a greater quantity of fuel, and thus increase the overall level of fuel costs, in order to produce the same amount of electricity.

The ECAC contains an efficiency factor, the target heat rate, that transfers plant efficiency risk to the Hawaiian Electric Companies, but also passes the cost and savings from uncontrollable changes in fuel prices to ratepayers in a timely manner.

Moving to a partial pass through for the first category of fuel cost changes would be harmful. Sharing of the risk of oil price fluctuations between customers and shareholders is not sound policy as the utility has no control over world oil markets. Exposing the Companies' financial condition to the vagaries of the world oil prices would put their financial viability at risk, raise the costs of capital and make it difficult for the Companies to fulfill the Commission vision for the future of Hawai'i's electric utilities. Hence such sharing is more likely to harm than to help customers and would not be fair to the utility as it would preclude recovery of prudently-incurred costs.

Specifically, the changes suggested by the Consumer Advocate would dampen the positive effects of the ECAC. As noted previously, these positive effects include:

- Reduction in the volatility of utility earnings.
- Granting the utility with a reasonable opportunity to recover its prudently-incurred costs in rates.
- Lowering the risks to capital invested in a utility and thus lower the utility's cost of capital (and ultimately, rates) as well as help maintain the utility's credit rating.
- Maintaining the Companies' liquidity. Because oil and other fuel expenses are a large portion of the Companies' operational costs, the ECAC is needed to enable them to raise capital in a time frame needed to meet expenses and investment requirements.

Importantly, changing the ECAC to fix 10% of the rate and pass through 90% of the fuel price changes is not a shared savings proposal. A shared savings mechanism is a regulatory mechanism that provides a utility an opportunity to share in the savings of an investment or action that saves resources, usually by reducing energy requirements. Examples could include conservation investments or investments that reduce losses. A utility that shares in such savings will have a financial incentive to pursue such investments and this is sensible. It is wrong to confuse arbitrarily subjecting Hawaiian Electric to "sharing" in the impact of deviations between forecast and actual world oil prices and sharing savings. Deviations can go either way. Deviations are not primarily a result of utility actions that can be incentivized. Such a proposal is not a shared savings proposal in the sense that that term is typically used in the utility industry. Instead it is a blunt force approach to make oil burning financially untenable and force Hawaiian Electric off oil. It is not shared savings but the imposition of a financial risk on Hawaiian Electric and on its customers. As such it is inappropriate and likely ineffective. While it may be intended to drive Hawaiian Electric off of oil, it will make it very difficult for Hawaiian Electric to achieve that objective as it will deny Hawaiian Electric and its customers the financial stability that Hawaiian Electric needs to deploy the investments needed to reduce oil usage.

X. Incentives to Invest in and Operate Renewables

As noted, other parties to this proceeding contend that the Hawaiian Electric Companies do not have proper incentives to invest in or operate renewables. We examine their incentives both with respect to operations – using as much renewable energy as possible given the installed resources mix and infrastructure—and with respect to development – taking investment and contracting actions to expand renewable resources usage economically.

With respect to operations, the ECAC clearly and directly encourages the Hawaiian Electric Companies to efficiently maintain and operate existing resources. The Companies currently experience the full gains or losses associated with heat rate deviations outside of their respective deadbands from the heat rate target for each fuel. This provides the Companies an incentive to achieve what is established as an appropriate heat rate target as they would absorb losses due to high heat rates outside of the deadbands.

It is the case that certain operational efficiency elements are neither incentivized nor discouraged by the ECAC. For example, the ECAC does not provide a direct reward or financial incentive to reduce curtailment of renewable energy. At the time that NERA last examined the ECAC and its compliance with Act 162, this was not a significant issue. Renewable penetration was not high enough that curtailment was a significant concern and the heat rate incentive in the ECAC provided the predominant operational efficiency incentive necessary under Act 162. Currently, however, curtailment of renewables is a major focus, particularly in the case of Maui Electric. We understand that the Companies and Commission are addressing curtailment in other contexts and believe that it is appropriate to do so. A shared savings mechanism related to reduced renewable curtailment would be complicated and may be counter-productive as minimization of curtailment could be contrary to minimizing costs and maximizing cost effective renewable development.

It is necessary to recognize that the ECAC is just one element of a regulatory structure that is founded on the bedrock that the utility has an obligation to operate prudently in order to minimize cost and has the right to recover only costs that are prudently incurred. This obligation extends to making prudent unit commitment and dispatch decisions – including operational decisions that will reduce renewable curtailment. This is precisely how the Companies operate under economic dispatch as shown in Appendix N to the Power Supply Improvement Plans.

The ECAC provides no impediment to efficient operation and reduction of renewable curtailment. The purchased power costs of renewable energy are eligible for ECAC recovery, and as a result the Hawaiian Electric Companies receive recovery of their costs, subject to the target heat rate deadbands, irrespective of their megawatt-hour production levels. At the same time, however, the ECAC provides no direct incentive to reduce renewable curtailment; that is left to the obligation to operate prudently.

In summary, NERA concludes that while the ECAC does not provide a direct incentive to reduce renewable curtailment, other aspects of the regulatory system appropriately fill that need and the ECAC does not provide any disincentive.

Incentives to Invest in and Operate Renewables

With respect to renewable development or the encouragement of new renewable development through the Companies contracting or infrastructure improvements to accommodate renewables, the ECAC does provide an appropriate and sufficient incentive for efficient renewable development. The ECAC covers all purchased energy costs, including renewable sources, on an equal footing within the cost recovery mechanism. Renewable energy resources can be part of a utility's power procurement to the extent that they are cost-efficient, reliable and represent a diverse source of generation relative to the traditional non-renewable resources. The ECAC provides a cost recovery mechanism for these resources.

Like many utilities, the Hawaiian Electric Companies create and follow resource planning procedures[23], which determines the extent of renewables used in the Companies' fuel mix. The resource planning process, as evidenced by the Power Supply Improvement Plans, balances cost-minimization with resource diversity and other concerns. Like purchasing fuel oil from the oil markets, purchasing energy from renewables is not without risks. To ensure the efficient use of renewable resources, the ECAC should and does cover all purchased energy costs, including renewable sources, on an equal footing.

Elements of the overall regulatory and costs recovery system in Hawai'i – *e.g.*, the inclusive nature of the ECAC with respect to all technologies, the resource planning process, the renewable portfolio standards and associated penalties for not achieving these standards in Hawai'i law, the decoupling mechanism, and ability to use a surcharge for renewable investments– provide the incentives for the Companies to incorporate renewable energy into their supply portfolios. Specifically, they provide for the timely recovery of renewable energy purchases and facilitate infrastructure investments.

With respect to transmission investment, if the Commission perceives a lack of transmission investment the appropriate solution is to provide incentives for such investment as the FERC has done with incentive returns and formula transmission rates that provide for full costs recovery. These include over two dozen incentive mechanisms granted within the context of Section 219 of the Federal Power Act.[24]

In summary, the Hawaiian Electric Companies are able to recover fuel costs and renewable costs on essentially equal footing and the ECAC provides no disincentives to acquiring the quantity of renewable energy that has been approved by the Commission. The ECAC is a cost recovery mechanism and its primary purpose is to protect both the utility and the customer from sudden swings in oil prices. Long-run resource development is accomplished through a variety of other

[23] We note that Decision and Order No. 32052 rejected the latest integrated resource plan and suspended further activities and requirements pursuant to the IRP Framework for the Hawaiian Electric Companies in the latest IRP planning cycle, and that the Commission has directed the Companies to file Power Supply Improvement Plans that the Commission will review in a separate proceeding. However, the Companies continue to engage in resource planning and we note that PSIPs have been filed and anticipate that in the future the IRP or a similar process will resume.

[24] For additional detail, see http://www.ferc.gov/industries/electric/indus-act/trans-invest.asp.

processes overseen by the Commission including the resource planning process and various specific Hawaiian Electric and Commission initiated proceedings. These processes provide a variety of stakeholders with input that is developed and evaluated over time. The ECAC appropriately supports this process by remaining neutral to the long-term resource choice and infrastructure investment decisions developed through these processes.

There is one additional way in which the ECAC supports the development of renewable resources and infrastructure. The ECAC has positive financial implications and can improve a utility's credit ratings, thereby moderating the cost of capital borne by ratepayers. In addition, the utility serves as a counter-party for renewable energy companies, so its credit standing frequently serves as an important determinant of the financial viability of renewable energy projects. Weakening the utility's credit rating through partial power cost recovery could harm renewable resources that rely on utility counter-party credit to support their investments. The ECAC can help the Hawaiian Electric Companies to retain their current level of credit worthiness, which is essential for renewable IPP financing. By contributing to utility financial health, the ECAC, in turn, accommodates renewable energy investment.

NERA concludes that a fuel adjustment clause with a target heat rate efficiency incentive that recovers renewable energy costs on an equal footing is appropriate and facilitates the integration of renewables for purposes of operations and resource development.

XI. The ECAC in the Context of a Shifting Fuel Mix

The economics of electricity in the state of Hawaii have changed and the possibility to reduce significantly the use of oil as the primary fuel for electric generation without necessarily increasing costs, or perhaps even reducing costs, appears potentially realistic. Among other things, the Companies are actively investigating the substitution of LNG for oil, in order to reduce fuel costs over the long term. See Appendix I of Hawaiian Electric's PSIP filed on August 26, 2014 in Docket No. 2011-0206. The Commission has indicated that it is concerned that "under the cost pass-through structure of the ECAC mechanism, the HECO companies have no direct financial incentive – reward or penalty – to stabilize and reduce power supply fuel costs, minimize curtailment of low cost renewable energy, or maximize the use of cost effective renewable energy resources."[25]

The Commission envisions that there must be in place "properly structured power generation costs recovery and financial incentive mechanisms to guide and reward the HECO Companies for implementing strategies and actions"[26] to create a 21st century generation system and to create modern transmission and distribution grids.

Previously in this report NERA has explained how the ECAC provides incentives for efficient operation through the use of heat rate efficiency targets and provides incentives to develop renewable energy by providing for the recovery of renewable energy costs through the ECAC and the recovery of renewable infrastructure investments through a surcharge. At the same time it protects customers and the utilities from variations in the price of fuel over which the utilities have no control. In this regard it is consistent with regulatory practice in most states and all that provide for FACs.

It is, however, true that the incentives in the ECAC are primarily short run in nature. The ECAC is neutral with respect to intermediate and longer run strategies and actions. Investments that may reduce curtailments or actions such as the retirement of older generation facilities are neither discouraged nor encouraged through the ECAC. From a regulatory economics perspective, this is appropriate. While it may seem that the ECAC, which protects customers and the utilities from fluctuations in the volatile price of oil does not provide the Companies an incentive to retire oil generation or to make investments that would reduce the need to operate oil generation in certain locations, it is also important to realize that the short-term recovery of fuel costs through the ECAC is not an effective or efficient way to impact these decisions.

The absence of an ECAC or a significant change to the degree of ECAC pass-through or dead bands may well render it too risky for the Companies to maintain oil fired generation even when economic; it could well encourage the Companies to move away from oil even if it were not in

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[25] Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities, attached to the Order in Docket No. 2012-0036, p. 23.

[26] *Id*, p. 24.

the customer’s best interests in order to reduce financial risks. This could have important implications for reliability as well. The ECAC is a short term regulatory mechanism that is best left neutral to long-term resource economics and investment choices. This is how it operates in the many states that have FACs.

To implement the vision set forth by the Commission to develop a transmission and distribution and energy storage infrastructure that will accommodate widespread dispersed renewable generation, significant steps must be taken by the incumbent utilities. If the Hawaiian Electric Companies are to make new investments themselves and to provide financial and contractual backing for investments made by independent generators, they will need the requisite financial strength and credit to do so. Hawai‘i can replace oil generation, but will have to invest to do so. Even with aggressive renewable development, a significant amount of oil will be required by the Companies in the near term. Absent a mechanism like the ECAC, which is essential to maintain fairness both to customers and to investors in the face of oil price volatility, the Companies would at a minimum face significantly higher financing costs and would likely have a difficult time raising the capital needed to implement the Commission’s vision. Hence the ECAC is an essential part of the regulatory structure needed to implement the Commission’s vision for the future of Hawai‘i’s electric utilities.

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Survey of Fuel Adjustment Clauses in Other States[1]

Jurisdiction	Description	Are incentives built into the FAC?	Is utility exposed to risk sharing for factors outside of its control ?
Alabama	An Energy Cost Recovery (ECR) mechanism is in place for Alabama Power. The ECR mechanism is established on the basis of estimates of electric sales, fuel-related costs, and purchased power costs, and also reflects accumulated over- or under-recovered amounts. Through it, Alabama Power recovers the costs associated with purchases of natural gas for its electric generating facilities. It may also recover financial hedge costs, subject to certain limits on the duration and size of hedging activities.	No	No. Allows for 100% pass through of fuel and purchased power costs.
Alaska	Electric fuel and gas commodity costs are recovered through adjustment mechanisms that are separate from base distribution tariffs. Alaska Electric Light and Power utilizes a power cost adjustment that is updated annually.	No	No. Allows for 100% pass through of fuel and purchased power costs.
Arizona	Arizona Public Service operates with a Power Supply Adjustor (PSA), a mechanism that permits the deferral and recovery of fuel and purchased power costs outside of a formal base tariff review. The PSA currently incorporates a forward-looking estimate of fuel and purchased power costs to set a rate that is subsequently reconciled with actual costs. The PSA reflects both a "forward component" that recovers or refunds differences between expected fuel and purchased power costs and those reflected in base rates and a "historical component," which tracks the differences between actual costs and those recovered through the combination of base rates and the forward component.	No	The initially established PSA included restrictions as to the amount of costs that could be deferred and recovered. For instance, it used to include a 90%/10% cost sharing component of the PSA (whereby the company absorbed 10% of fuel and purchased power costs that are in excess of the amount reflected in base rates). In the company's subsequent rate proceedings, however, the ACC eliminated this sharing mechanism. The current PSA has a cap whereby the adjustor rate cannot decrease or increase by more than 4 million in a given year.
Arkansas	Electric utilities recover fuel and purchased power costs through Energy Cost Recovery (ECR) Riders. The ECR rider is calculated annually, reflecting the actual cost in the previous calendar year, with an adjustment for projected changes. ECR rate changes are implemented automatically; however, a utility's ECR rider calculation is subject to a 15-day review period. The Staff of the regulatory commission is permitted to audit any utility's ECR rider and can recommend adjustments to the ECR rate filed by the company. Any such adjustments would typically be made in the next year's true-up.	No	No. Allows for 100% pass through of fuel and purchased power costs.
California	The state's electric utilities utilize a balancing account, the Energy Resource Recovery Account (ERRA), that is designed to track and allow recovery of the difference between electric procurement costs included in rates and actual costs incurred under each utility's procurement plan. The regulator must review the revenues and costs associated with each utility's electricity procurement plan at least annually and adjust retail electricity rates or order refunds, as appropriate, typically once a year. In addition, rate changes can be implemented based on the ERRA trigger mechanism, which is effective when aggregate over-collections or under-collections exceed 5% of the utility's prior year electric generation revenues, excluding amounts collected for the DWR. The PUC would make the final determination of an ERRA trigger mechanism rate change.	No	No. Allows for 100% pass through of fuel and purchased power costs.
Colorado	Public Service Company of Colorado's (PSCO's) fuel and purchased energy costs are recovered through an incentive based electric commodity adjustment (ECA) that compares actual fuel and purchased power expenses to a formula-based benchmark. The ECA also contains certain earnings-sharing provisions related to energy trading activities (see the Alternative Regulation section). Since 2004, PSCO has utilized a purchased capacity cost adjustment (PCCA) clause that allows for recovery of the costs of purchased power not included in base rates or other recovery mechanisms. Effective Jan. 1, 2011, the PUC authorized PSCO to recover via the PCCA, subject to certain adjustments, operations and maintenance and capital costs associated with the company's investment in the gas-fired 652-MW Rocky Mountain Energy Center and the 310-MW Blue Spruce Energy Center until PSCO's next electric rate case. The two plants were purchased by PSCO on Dec. 6, 2010, from Calpine Corporation for $739 million. Prior to the acquisition, the two facilities served PSCO through purchased power agreements. In 2012, the costs associated with the Calpine assets were rolled into base rates and removed from the PCCA clause. Black Hills Colorado Electric Utility Company (BHCE) is subject to an energy cost adjustment mechanism under which all fuel and purchased energy cost differences from the company's base energy cost rate are fully recovered from, or credited to, customers. The impacts of certain incentive mechanisms also flow through the mechanism (see the Alternative Regulation section).	Yes - Actual fuel and purchased power expenses are compared to a formula-based benchmark. Public Service Company of Colorado share margins from generation-based short term energy trading and proprietary trading, where margins that exceed a certain amount are allocated 90% to ratepayers and 10% to shareholders. Black Hills has an off-system sales margin-sharing mechanism, where margins are allocated 75% to ratepayers and 25% to shareholders.	No. Allows for 100% pass through of fuel and purchased power costs.
Connecticut	United Illuminating (UI) and Connecticut Light & Power (CL&P) are permitted to recover their full costs of providing generation service to those customers who do not choose an alternative supplier. Tracking mechanisms are in place for CL&P and UI that provide for semi-annual adjustments to reflect Federal Energy Regulatory Commission-approved transmission costs. As part of a 2009 rate decision for UI, the PURA adopted pension and cost-of-debt tracking mechanisms, both of which were discontinued in 2011. Purchased gas costs that differ from the levels reflected in base rates are reflected in purchased gas adjustments (PGAs), which are modified monthly. Over- or under-recoveries are refunded to, or collected from, customers during a subsequent 12 month period. A local gas distribution company may suspend or discontinue its PGA clause if approved by the PURA.	Customer choice state. Full pass through without incentives.	Customer choice state. 100% pass through without risk-sharing.
Delaware	In conjunction with the implementation of retail competition, the electric fuel adjustment was largely eliminated. Power to meet SOS needs is now procured competitively and reflected in rates accordingly (see the Electric Regulatory Reform/Industry Restructuring and Integrated Resource Planning sections). In addition, Delmarva is permitted to submit annual filings to update prices to reflect changes in FERC-approved transmission charges. Gas cost adjustment clauses (GCA) are permitted, with changes implemented subject to investigation and hearing. GCA clauses are re-set annually based on estimated annual gas commodity costs. Under- or over-recoveries are trued up annually. Delmarva also has a clause in place that permits timely recovery of gas-related environmental compliance costs.	Customer choice state. Full pass through without incentives.	Customer choice state. 100% pass through without risk-sharing.
District of Columbia	Fuel and purchased gas adjustment clauses are permitted by law. However, with the onset of electric retail competition, Potomac Electric Power (Pepco) divested most of its generation assets. Pepco purchases the power to meet its SOS requirements via a competitive bidding process, and prices paid by SOS customers reflect the weighted average of the winning bids (see the Electric Regulatory Reform/Industry Restructuring section).	Customer choice state. Full pass through without incentives.	Customer choice state. 100% pass through without risk-sharing.

Jurisdiction	Description	Are incentives built into the FAC?	Is utility exposed to risk sharing for factors outside of its control ?
Florida	The fuel and purchased power cost recovery clause (FPPCRC) provides for recovery of prudently incurred fuel and purchased power costs. Annual fuel factors are established based upon 12-month projections of fuel costs and energy purchases and sales. Hearings are held each November, during which the PSC sets fuel factors for the next calendar year. Subsequent to the November hearings, utilities may seek, or the PSC may require, a mid-term modification to the factors if updated projected costs for the year vary from updated projected revenues by plus or minus 10%. Interest is accrued on both over- and under recovered balances. Included in the FPPCRC is a generating performance incentive factor that provides a financial reward or penalty when a company's base load generating units' availability and heat rate vary from targets approved by the PSC. The reward or penalty is limited to a 25-basis-point ROE spread. The PSC generally requires market-based pricing of coal purchased from an affiliate. The FPPCRC also reflects gains from economy energy sales. A three-year moving average based on eligible sales is determined, and 100% of the sales up to this benchmark are credited to ratepayers. For sales above the benchmark, 80% of the gains from such sales accrue to ratepayers, with 20% retained by the companies. A capacity cost recovery clause (CCRC) is also in place as a component of the FPPCRC. The capacity component of purchased power agreements are flowed through this clause on an annual basis. In addition, utilities may recover all prudently incurred site selection and preconstruction costs, including carrying charges, for nuclear and integrated gasification combined-cycle (IGCC) power plants through the CCRC. A cash return on construction work in progress (CWIP) for nuclear plant construction and uprates and IGCC construction is also reflected in the CCRC.	Yes - Generating performance incentive factor that provides a financial reward or penalty when a company's base load generation units' availability and heat rate vary from approved targets (reward/ penalty up to 25 basis point ROE spread).	No
Georgia	A non-automatic fuel adjustment mechanism, known as the fuel cost recovery clause, is in place for Georgia Power (GP). Hearings are required before increases or decreases are implemented. Electric fuel rates are based on estimated sales and fuel costs, and any balance of previously unrecovered/over-recovered fuel costs is considered in setting new rates. The energy portion of purchased power transactions is reflected in the mechanism; the capacity component is recovered through base rates. The cost of GP's natural gas and oil procurement hedging program, including any net gains or losses, are also recovered through the fuel cost recovery clause.	No	No - subject to regulatory review.
Hawaii	Fuel adjustment clauses are in place for electric utilities. The clauses are adjusted monthly for changes in fuel costs and the fuel-cost component of purchased energy, and for variations from the forecasted generation mix. In 2011, Hawaiian Electric Company (HECO) was permitted to implement a purchased power adjustment clause (PPAC) designed to recover purchased power capacity costs and the operations and maintenance expense component of purchased power energy costs. Hawaii Electric Light Company (HELCO) and Maui Electric Company (MECO) were permitted to implement PPACs in 2012. Rates under the PPAC mechanisms are adjusted quarterly.	Yes. Performance factor around target heat rate.	No
Idaho	Electric power cost adjustment (PCA) mechanisms are utilized by Avista Corporation, Idaho Power (IP), and PacifiCorp. The PUC has the authority to implement semi automatic purchased gas adjustments. Electric and gas utilities may seek PUC approval to issue energy cost recovery (securitization) bonds to moderate the impact of power cost increases on customers (see the Securitization section). Avista Corporation's PCA enables the company to defer, in a balancing account, 90% of the difference between actual net power costs and the amount included in retail rates. IP has a similar mechanism in place with a sharing provision under which annual rate adjustments reflect 95% of the cost variations associated with water supply for hydro-electric production, wholesale energy prices, and retail load changes. An energy cost adjustment mechanism is in place for PacifiCorp that allows for the recovery of 90% of the difference between actual power costs and those included in rates.	No	Yes - Avista's PCA allows it to defer 90% of the difference between actual net power costs and the amount included in retail rates. Pacificorp can recover 90% of the difference between actual power costs and those included in rates.
Illinois	Fuel/Power Costs--Historically, the large electric utilities, namely Ameren Illinois (AI) and Commonwealth Edison (ComEd), were permitted to recover fuel costs and the energy component of purchased power costs through a monthly automatic fuel adjustment clause (FAC); however, the FAC was discontinued in conjunction with the implementation of electric restructuring. The power to meet the utilities' standard offer service (SOS) obligations is now procured competitively (see the Electric Regulatory Reform/Industry Restructuring section); SOS costs and revenues are subject to an annual true-up mechanism. MidAmerican Energy (MidAmerican) continues to use an FAC, as the company was not subject to the provisions of the restructuring law, and continues to own generation plants to serve its customers.	Restructured state. FAC discontinued for all companies except for MidAmerican Energy, which still uses a FAC. All companies permitted full pass through without incentives.	Restructured state. FAC discontinued for all companies except for MidAmerican Energy, which still uses a PCA. All companies permitted 100% pass through without risk sharing.
Indiana	Electric fuel (the fuel adjustment clause [FAC]) and purchased gas adjustment provisions are permitted. State law also permits recovery of certain other costs through adjustment mechanisms. FAC proceedings--Electric utilities may adjust rates for changes in fuel and purchased power (energy component only) costs every three months, following hearings, through the FAC. The FAC is based on estimated costs of fuel and purchased power for a future three-month period, with an additional factor to account for over- or under recoveries caused by variances between estimated and actual costs in the previous three-month period. No carrying charges accrue on over- or under-recoveries. The adjustment factor may be modified more frequently than every three months under emergency circumstances. By law, the URC may not approve an FAC rate adjustment if it will result in the utility earning a net operating income (NOI) in excess of that authorized. Duke Energy Indiana (DEI) is authorized to recover 100% of purchased power capacity/demand charges through a summer reliability tracking mechanism that is to remain in place until the company's next base rate proceeding. The fuel component of purchased power is recovered through the FAC.	No	No
Iowa	Energy adjustment clauses (EACs) are modified monthly based on forecasted energy costs (fuel and purchased power) for two months. The capacity/demand portions of purchased power are recovered through base rates. Under- and over-recoveries are deferred and charged/credited to customers in the succeeding months. Interstate Power & Light (IP&L) uses an EAC that provides for recovery of fuel and purchased power costs as well as revenues and costs associated with sales or purchases of emission allowances. As part of a settlement, MidAmerican Energy's (MidAmerican's) EAC was eliminated in 1997 in conjunction with implementation of an alternative regulation plan, and a fixed EAC revenue level was rolled into base rates.	No	No

Jurisdiction	Description	Are incentives built into the FAC?	Is utility exposed to risk sharing for factors outside of its control ?
Kansas	Electric fuel (the energy cost adjustment [ECA]) and purchased gas adjustment (PGA) mechanisms are permitted. State law also allows recovery of certain other costs through adjustment mechanisms. ECA Proceedings--The major electric utilities have ECA mechanisms in place to recover variations in fuel and purchased power costs. The ECA is calculated monthly based on projected fuel and purchased power costs for that month, with any under- or over-recoveries reflected in the subsequent month. Penalties may be imposed if actual costs exceed projections for three consecutive months. Those utilities using an ECA mechanism are required to annually discuss fuel planning and purchasing practices with the Staff; fuel contracts are to be competitively bid whenever possible. Any contracts awarded after a competitive bidding process that has been endorsed by the Staff are accorded a "presumption of reasonableness" by the KCC. Any contract longer than one month that is not competitively bid must receive KCC approval before the effective date. The major electric utilities in Kansas, Empire District Electric, Westar Energy (Westar), Kansas Gas & Electric (KG&E) and Kansas City Power & Light (KCP&L), currently utilize ECA mechanisms. Westar and KG&E adjust their ECA mechanisms quarterly. All of the utilities flow to ratepayers, through their ECA mechanisms, 100% of off-system sales (OSS) margins that vary from a base level, as well as the net cost of emission allowances.	No	No
Kentucky	Electric Fuel Adjustment Clauses (FACs)--The PSC allows fuel and purchased power (energy only) costs to be recovered through automatic fuel adjustment clauses (FACs). Adjustments are implemented monthly, based on actual costs for the second preceding month (producing a two-month lag), with an under- or over-recovery mechanism included in the clause. Incremental replacement power cost increases resulting from forced outages cannot be recovered through the FAC. Public hearings are held every six months to examine procurement and other practices related to fuel and purchased power cost recovery, and adjustments are made to correct for any costs that the PSC determines are unjustified. Additional proceedings are conducted every two years to evaluate the operation of the clause and to set the level of such charges to be included in base rates.	Yes - Incremental replacement power cost increases resulting from forced outages cannot be recovered through the FAC.	No
Louisiana	Fuel and purchased power (energy only) costs are recovered through the fuel adjustment clause (FAC). The demand component of purchased power costs related to "economy" purchases (entered into by a company when the price of the purchased power is below the cost of the company's own generation) may also be recovered through the FAC. Monthly filings are required for implementation of changes in the adjustment factor. The major utilities accrue over- or under-recoveries, with the bulk of the accumulated balances refunded/recovered over subsequent 12-month periods. The PSC may audit a utility's purchased power and fuel acquisition practices, and if the Commission determines that the charges passed through the FAC were unreasonable, refunds may be required. For certain utilities, the PSC requires that revenues related to off-system sales (OSS) be recognized through the FAC.	No	No
Maine	Electric fuel adjustment clauses are no longer utilized due to the implementation of retail choice. For the most part, the state's electric utilities no longer own generation, and by law are not allowed to provide standard offer service (SOS). SOS power providers are selected through a bidding process conducted by the PUC. The full cost of SOS is recovered from ratepayers. Semi-annual or monthly cost-of-gas adjustment mechanisms are utilized for Northern Utilities, Bangor Gas and Maine Natural Gas. Northern Utilities also recovers manufactured gas site remediation expenses through an environmental remediation rate adjustment that is set on a semi-annual basis.	Restructured state. Full pass through without incentives.	Restructured state. 100% pass through without risk-sharing.
Maryland	Historically, electric utilities were permitted to recover the fuel and energy portion of purchased power costs through the electric fuel rate (EFR). The EFR was eliminated, coincident with the implementation of competition in the provision of electric supply. The utilities continue to provide electric supply service to customers who do not select an alternative generation supplier, and the power to meet these requirements is obtained via competitive bids.	Restructured state. Full pass through without incentives.	Restructured state. 100% pass through without risk-sharing.
Massachusetts	Fuel/Gas Commodity--Quarterly electric fuel and purchased power adjustments were eliminated in 1998, coincident with the start of retail competition. Restructuring orders adopted for most of the electric utilities allowed the rates for standard offer service (SOS) that was available from 1998 through February 2005, to include an SOS fuel adjustment (SOSFA) to reflect fluctuations in the market price of oil and gas. Marketpriced default service was also available during the 1998-through-February 2005 period for those customers who were not eligible for SOS and were not receiving generation service from a competitive supplier. SOS service has not been offered since 2005. Default service was extended beyond 2005, and is now called "basic service." Rates for basic service are market-based; such rates reflect the competitive solicitations for basic service supply undertaken by the distribution utility. The utilities are not at risk for fluctuations in market prices. Electric utilities recover the energy-related portion of bad debt cost through their basic service rates.	Restructured state. Full pass through without incentives.	Restructured state. 100% pass through without risk-sharing.
Michigan	The Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) clauses require utilities to annually file projected costs, and a forward-looking PSCR or GCR supply factor is established at the beginning of the 12 month collection period. Annual reconciliation proceedings are required. Carrying charges are accrued on over-collections at the higher of the short-term borrowing rate or the authorized ROE for the utility, with under-recoveries permitted to accrue interest at the short-term borrowing rate. Full recovery of prudently expended amounts is required. For electric utilities, the capacity and energy components of purchased power costs are recoverable through the PSCR clause. In addition, for DTE Electric (DTE-E), Consumers Energy (CE), and Upper Peninsula Power (UPP), transmission costs flow through the PSCR.	Restructured state. Full pass through without incentives.	Restructured state. 100% pass through without risk-sharing.
Minnesota	Automatic fuel and purchased gas adjustment (PGA) clauses are permitted. For most electric utilities, the electric fuel clause is adjusted monthly with a two-month lag. For Northern States Power-Minnesota, the PUC permits a forecasted fuel clause that projects monthly costs and provides for a true-up to actual costs. Electric utilities are permitted to recover through the fuel adjustment clause non-administrative Midwest Independent Transmission System Operator Day 2 costs. The electric utilities are required to submit to the PUC an annual report regarding the operation of the electric fuel clause.	No	No

Jurisdiction	Description	Are incentives built into the FAC?	Is utility exposed to risk sharing for factors outside of its control ?
Mississippi	PSC rules provide for automatic electric fuel adjustment clauses, with the energy component of purchased power recovered through the fuel clause and the capacity component recovered in base rates. Both Mississippi Power (MP) and Entergy Mississippi (EM) use levelized fuel adjustment clauses based upon projected fuel use and costs, with a provision for the reconciliation of over- and under-recoveries. MP's fuel adjustment is set for a 12-month period, while EM's is adjusted quarterly. Atmos Energy operates under a purchased gas adjustment rider that is updated monthly. The PSC must conduct an annual audit of all fuel purchases and interchange contracts and submit an annual report to the Legislature. EM and MP also have separate energy cost management clauses to recover fuel hedging gains, losses, and expenses. EM and MP may recover emissions allowance expenses through their adjustment clauses.	No	No
Missouri	State statutes permit the electric utilities to request PSC approval of mechanisms that allow for the recovery of costs related to fuel and purchased power, environmental compliance, renewable energy, gas commodity costs and certain other items. Fuel Adjustment Clauses (FACs)--According to the PSC's rules: an application for approval of an FAC must be submitted within the context of a general rate case or complaint proceeding; an FAC should provide the utility an opportunity to earn a "fair return on equity"; the Commission may adjust a utility's allowed return in future rate proceedings if it determines that implementation of an FAC would alter the utility's business risk; incentive features may be incorporated into an FAC to improve the efficiency and cost-effectiveness of a utility's fuel and purchased power procurement activities; an FAC is to be subject to true-ups for under- and over-collections, including interest; an FAC may reflect incremental variations in off-system sales (OSS) margins; an FAC may remain in place for a maximum four-year term, unless the PSC were to authorize an extension in the context of a general rate case (the utility must file a rate case within four years after implementation of an FAC); and, such mechanisms are to be subject to a prudence review every 18 months. KCP&L Greater Missouri Operations' FAC, implemented in 2007, is adjusted semi-annually. Costs recovered through the FAC include 95% of "prudently incurred" fuel and purchased power costs, net emissions allowance costs, and OSS margins that vary from the levels included in base rates. Empire District Electric (Empire) utilizes an FAC that provides for the company to flow to/recover from ratepayers, on a semi-annual basis, 95% of the fuel and purchased power costs, net emissions allowance costs and revenues, and OSS margins that vary from the levels included in base rates. Union Electric (UE) utilizes an FAC, implemented in 2009 and modified slightly in 2011, that provides for the company to recover from/flow through to ratepayers 95% of incremental variations in both fuel and purchased power costs, and OSS margins from the levels included in base rates. UE's FAC incorporates an eight-month recovery period and includes the net costs associated with the purchase or sale of SO2 and NOx emission allowances. A comprehensive infrastructure expansion program approved by the PSC in 2005 prohibits Kansas City Power & Light (KCP&L) from seeking implementation of an FAC before June 1, 2015. However, the company is permitted to request approval of an interim energy charge (IEC) that would provide for limited recovery of fuel and purchased power costs, prior to that date.	No	Yes - Kansas City Power and Light, Union Electric, and Empire District Electric can recover 95% of fuel and purchased power costs, net emissions allowance costs and revenues, and OSS margins that vary from the levels included in base rates
Montana	In accordance with the state's restructuring statutes, NorthWestern Corp. (then Montana Power) sold its generation assets in 1999 and subsequently entered into purchased power contracts with competitive suppliers to serve provider-of-last-resort customers. NorthWestern recovers supply costs through a cost recovery mechanism, adjusted monthly, under which rates are based on estimated loads and electricity costs for the upcoming tracking period. The PSC reviews and adjusts rates for differences between estimates and actual results. NorthWestern is also permitted to recoup revenues lost as a result of demand-side management programs in the context of its annual default supply cost recovery filings. MDU Resources (MDU) utilizes a monthly-adjusted fuel and purchased power cost adjustment mechanism that contains certain incentive provisions.	No	Yes - MDU Resources has a PCA under which incremental changes in fuel and purchased power costs, and off-system sales margins are share by ratepayers and shareholders on a 90%/ 10% basis
Nebraska	Semi-automatic purchased gas adjustment mechanisms are in effect for the state's natural gas utilities.	No - No indication of PCA for Electric utilities	No - No indication of PCA for Electric utilities
Nevada	Electric utilities are subject to a deferred energy cost recognition procedure, under which Commission approval is required prior to implementation of changes in the recovery of fuel and purchased power costs. In accordance with this procedure, Nevada Power Company (NPC) and Sierra Pacific Power (SPP) file quarterly deferred energy adjustment applications (DEAAs) proposing to recover or refund the deferred balances, representing the difference between actual fuel and purchased power costs incurred and the amounts currently reflected in rates. Electric utilities must reset, on a quarterly basis, the rate for ongoing fuel and purchased power costs, referred to as the base tariff energy rate (BTER). The quarterly reset is designed to reflect power costs on a more current basis, thereby eliminating large deferred energy balances. These quarterly BTER adjustments are reviewed annually by the PUC as part of the companies' DEAA filings. Costs eligible for recovery include all prudent expenses incurred to purchase fuel, capacity, and energy, as well as the carrying charges on the deferred balances. The burden of proof regarding prudence rests with the utility.	No	No
New Hampshire	Fuel and purchased power adjustment clauses (FPPACs) had been utilized prior to the implementation of competition in the early 2000s. Public Service Company of New Hampshire (PSNH) now recovers its power costs through a periodically-adjusted default service rate, which reflects the revenue requirements of its generating assets and the cost of power purchases. It also includes a reconciliation of the difference between the company's costs and revenues for the previous period. A transmission cost adjustment mechanism (TCAM) is also in place for PSNH. The TCAM, which is designed to provide recovery of all transmission-related costs, is adjusted annually each July 1.	Restructured state. Full pass through without incentives.	Restructured state. 100% pass through without risk-sharing.
New Jersey	Historically, the electric utilities were permitted to reflect variations in fuel and purchased power costs through the Levelized Energy Adjustment Clause (LEAC); however, the LEAC was suspended in 1999, with the onset of electric retail competition. The utilities now procure power to meet customer requirements in the wholesale market and are permitted to flow these costs to ratepayers on a dollar-for-dollar basis.	Restructured state. Full pass through without incentives.	Restructured state. 100% pass through without risk-sharing.

Jurisdiction	Description	Are incentives built into the FAC?	Is utility exposed to risk sharing for factors outside of its control ?
New Mexico	Commission rules provide for automatic fuel adjustment clauses; the fuel and purchased power cost adjustment clause (FPPCAC) for an electric utility is calculated monthly (a variance from monthly reporting may be sought), and includes a balancing account in which there is approximately a two-month collection lag. A utility is required to reapply for continuation of an FPPCAC every four years, at which time a comprehensive review of the clause is undertaken. In 2008, the PRC authorized Public Service Company of New Mexico (PSNM) to establish an emergency FPPCAC. The clause contained several conditions, including that the recoverable costs were subject to a prudence review. (PSNM's FPPCAC had been eliminated in 1994, following a stipulation.) In 2009, the PRC adopted a rate case settlement that included the reinstatement of the company's FPPCAC on a permanent basis. The fuel factor is adjusted annually. Additionally, the approved settlement contained an SO2 rider through which customers are credited with their share of revenues from allowance sales. After three years of operating without an adjustment clause, El Paso Electric's FPPCAC was reinstated in 2001. As approved by the PRC, El Paso is permitted to seek approval to adjust the FPPCAC if the company experiences an over- or under-recovery balance of at least $2 million of fuel and purchase power expenses as of December 31 and June 30 of each year. Southwestern Public Service (SWPS) uses an FPPCAC under which it may petition for a change in the fuel factor if the over/under-recovery balance reaches $5 million. Under the terms of a rate settlement adopted by the PRC in December 2011, SWPS was permitted to file for, and be authorized, recovery of deferred renewable portfolio standard costs through a rate rider prior to Jan. 1, 2014.	No	No
New York	Historically, all energy utilities used a semi-automatic fuel adjustment clause (FAC), through which variations in fuel and gas charges and purchased power costs were passed along to customers. With electric industry restructuring, however, generation was divested, and the electric companies have largely transitioned from the FAC to a market power adjustment clause (MAC) or a commodity adjustment clause (CAC). The MAC/CAC allows the distribution utilities to flow through the costs of power procured to serve customers who have not selected an alternative supplier. Changes in the clause are recognized in each customer bill (i.e., monthly, bi-monthly, etc.). Although the incumbent distributors retain the provider-of-last-resort obligation, the operation of these clauses leaves the distributor insulated from any financial effects associated with changes in market prices.	Restructured state. Full pass through without incentives.	Restructured state. 100% pass through without risk-sharing.
North Carolina	Prudent electric fuel and fuel-related costs are recoverable through a fuel adjustment clause (FAC). Each utility has an annual hearing to review fuel costs, with a test period determined by the NCUC for each company. The proceedings provide for a true-up of any over- or under-collections from the previous year, with interest included only for over-collections. The costs of certain re-agents (e.g., limestone) used in reducing or treating emissions, as well as certain non-fuel purchased power costs for economic purchases, may be recovered through the FAC. The law limits the annual increase in recoverable costs related to certain purchased power costs to 2% of a utility's total retail revenues.	No	No
North Dakota	Automatic fuel and purchased power (energy only) adjustments are in place for Northern States Power (NSP), MDU Resources Group (MDU), and Otter Tail Power (OTP). Fuel and purchased power cost adjustments are implemented monthly, and there is generally a two-month lag for recovery. In 2011, MDU was authorized to recover capacity costs associated with purchased power through its fuel and purchased power adjustment (FPPA) clause. In 2010, the PSC approved a settlement permitting MDU to recover roughly $9.6 million of costs associated with the cancelled Big Stone II coal plant over three-years through its FPPA clause. Following a settlement in 2010, the PSC authorized OTP to recover its share of costs associated with the cancelled Big Stone II plant (roughly $4.1 million) via a separate rider over three years.	No	No
Ohio	Electric-Related Mechanisms--As a result of electric industry restructuring, the utilities operate under electric security plans (ESPs) that allow for rate recognition of at least a portion of variations in fuel prices, purchased power costs, and emissions expenditures. The ESP includes a delivery capital recovery rider, implemented on Jan. 1, 2012, that reflects a return of and on distribution, sub-transmission, and general plant-in-service not included in the companies' 2009 distribution rate decisions. Under DEO's current ESP, the company is required to transfer its generating assets to an affiliate by year-end 2014. As such, Rider RC (retail capacity) and Rider RE (retail energy) were implemented, both of which are fully bypassable for switching customers. DEO also established a non-bypassable Rider ESSC (electric service stability charge) for the period Jan. 1, 2012, through Dec. 31, 2014, to provide the company with "certainty regarding [DEO's] provision of retail electric service" DEO's generation requirements for non-switching customers are now procured and priced through a competitive bid process. In August 2012, the PUC approved an ESP for Ohio Power (OP) that includes a three-year freeze on base (non-fuel) generation rates until May 31, 2015, when such rates are to be established through a competitive bid process. A bypassable fuel adjustment clause is to continue through that time. Additionally, the company is to undergo a phased-in transition to full market-based pricing for generation for non-switching customers by June 2015, and is to separate its generation and marketing businesses from its transmission and delivery businesses by Jan. 1, 2014. In the ESP, the company's Environmental Investment Carrying Charge Rider (EICCR) is now bundled with the frozen base generation rates, such that the previously separate EICCR no longer exists. The ESP also includes a non-bypassable Generation Resource Rider through which the distribution company recovers the costs associated with the construction of new (presumably regulated) generation dedicated to Ohio customers. Additionally, OP established a Distribution Investment Rider, through which the company is permitted to recover the costs associated with new distribution investment. Also, OP established Retail Stability Rider, which is similar to DEO's Rider ESSC (see above). In a 2011 base rate decision, OP was authorized to implement a Deferred Asset Recovery Rider through which the company is to fully recover certain regulatory assets over the seven years, 2012 through 2018.	Restructured state. Full pass through without incentives.	Restructured state. 100% pass through without risk-sharing.

Jurisdiction	Description	Are incentives built into the FAC?	Is utility exposed to risk sharing for factors outside of its control ?
Oklahoma	Fuel Adjustment Clauses (FACs)--Fully automatic FACs are prohibited in Oklahoma. However, semi-automatic FACs are in place. The OCC reviews each company's FAC at least every 12 months, but the utilities may propose more frequent changes if conditions warrant. Once the utility files for a change in its FAC rate, the Staff has five days within which to respond. If the Staff files objections to the change, a formal investigation is initiated; if the Staff files no objections, the proposed rates become effective. The FAC is then reviewed by the OCC at the end of the calendar-year to true up any under- or over-collections. OG&E's FAC is adjusted annually, subject to a cap on under- and over-recoveries. However, the annual factor may be adjusted more frequently, but not more than quarterly, if cost levels have changed or the under- or over-recovered balance exceeds 5% of the company's total annual Oklahoma-jurisdictional fuel cost. Otherwise, amounts that differ from the levels month's actual fuel cost calculations are deferred in a balancing account, and the deferrals are recovered over the subsequent 12-month period, with interest. Purchased power and certain cogeneration and capacity payment differentials are reflected in the FAC. OG&E also recovers a portion of the transportation costs associated with gas deliveries to its generating facilities through the FAC. PSO's FAC is adjusted annually, subject to a cap on under- and over-recoveries. However, an immediate adjustment is implemented if the under- or over-recovered balance exceeds $50 million. Otherwise, amounts that differ from the levels reflected in base rates are deferred in a balancing account, and the deferrals are recovered over the subsequent 12 months. The FAC also allows for current recovery of line losses above or below the amount recognized in PSO's base rates. Such under or over-recoveries are recovered from, or refunded to, customers during subsequent months. Ratepayers' 75% share of OSS margins flow through PSO's FAC.	No	No
Oregon	Until recently, power cost adjustment mechanism (PCAM) clauses had not been utilized in Oregon. However, in certain instances, the PUC had permitted utilities to defer for future recovery power supply costs that were higher than those included in base rates, subject to certain deadbands and sharing provisions. Portland General Electric (PGE), PacifiCorp, and Idaho Power (IP) are now permitted to annually adjust rates to reflect forecasted power costs. PGE's and IP's mechanisms include a component under which a portion of the difference between actual and forecasted power costs is deferred for future recovery or refund. PGE's current power cost recovery framework includes both an annual update, under which rates change each January 1, to reflect updated net variable power costs (NVPC), and a PCAM that is designed to capture a portion of the difference between the NVPC forecast (i.e., baseline NVPC) established through the annual update and the actual NVPC incurred by PGE for that year. The PCAM is subject to a deadband of $15 million below to $30 million above the ultimately established NVPC, a sharing ratio, and an earnings test. PGE absorbs 100% of the costs/benefits within a PUC-determined deadband, and amounts above or below the deadband are allocated 90% to customers and 10% to PGE shareholders. A refund would occur only to the extent that the refund would result in PGE's actual ROE for that year being no less than 100 basis points above PGE's last authorized ROE. A surcharge would occur only to the extent that the surcharge would result in PGE's actual ROE for that year being no greater than 100 basis points below PGE's last authorized ROE. PacifiCorp and IP do not have a similar mechanism.	No	Yes - PGE absorbs all costs and benefits within the -$15 million to $30 million deadband around the NVPC (net variable power cost) forecast, and amounts above and below are allocated 90% to customers and 10% to PGE shareholders
Pennsylvania	Now that each electric company's restructuring transition period has expired, generation required to meet provider of last resort (POLR) obligations is competitively procured and priced; therefore, the utilities are not at risk for changes in power prices. A non-automatic procedure is in place for recovery of fluctuations in gas costs. Tariff changes must be filed for PUC review six months prior to the proposed effective date. The companies may recover the difference in actual costs versus those projected, if the actual costs were reasonably incurred. Such filings may be made no more often than once every 12 months; however, quarterly updates to reflect unrecovered gas costs from the prior quarter are permitted.	Restructured state. Full pass through without incentives.	Restructured state. 100% pass through without risk-sharing.
Rhode Island	Prior to the implementation of electric industry restructuring in 1998, automatic electric fuel adjustment clauses were utilized by the utilities. In accordance with the restructuring law and PUC-approved restructuring plans, investor-owned utilities are to provide standard offer service to customers who do not select an alternative provider through 2020. The cost of providing this service is fully recoverable, with such rates reset on a periodic basis. In 2011, pursuant to legislation enacted in 2010, the PUC approved full revenue decoupling mechanisms for Narragansett Electric's (NE's) electric and gas operations. We note that prior to the enactment of the legislation, the PUC had rejected decoupling mechanisms proposed by NE. The 2010 law also provides for rate recognition of capital investments, as well as expenses associated with an electric service inspection and maintenance program and vegetation management program. Under the law, NE submits for PUC approval, annual infrastructure spending plans for its electric and gas operations. The revenue requirements associated with these plans are reflected in rates on a prospective basis, subject to adjustment to reflect actual capital investment and expense activities.	Restructured state. Full pass through without incentives.	Restructured state. 100% pass through without risk-sharing.
South Carolina	Non-automatic electric fuel and purchased gas adjustment clauses are in place for the state's utilities. Each electric utility is required to furnish the PSC an estimate of its fuel costs, including the cost of purchased power, for a prospective 12-month period. The PSC then determines the fuel-related costs to be included in base rates for that period, including adjustments for over- or underrecovery from the preceding 12-month period. Electric companies are required to account on a monthly basis for the difference between fuel costs recovered through base rates and actual fuel costs. Emissions allowance costs and the cost of certain materials used in reducing or treating emissions are reflected in the fuel clause.	No	No
South Dakota	Automatic fuel, purchased power, and gas cost adjustment clauses are permitted. Through these clauses, the utilities recover actual fuel, purchased power (energy portion only), and purchased gas expenses incurred; carrying costs accrue on unrecovered balances. Northern States Power (NSP) flows to ratepayers a portion of certain margins from wholesale power sales through its fuel clause (see the Alternative Regulation section). Black Hills Power (BHP) utilizes a fuel and purchased power adjustment clause (FPPAC) that allows the company to recover fuel and purchased power expenses and includes several sharing provisions (see the Alternative Regulation section).	No	No

Jurisdiction	Description	Are incentives built into the FAC?	Is utility exposed to risk sharing for factors outside of its control ?
Tennessee	Automatic purchased power and gas commodity recovery clauses are permitted. The state's gas utilities are allowed to reflect a portion of uncollectible expenses in these clauses. Kingsport Power (KP) has a purchased power adjustment rider that reflects any changes in the wholesale costs of the company's power supplier, affiliate Appalachian Power (APCO). KP has no generating capacity of its own, and purchases 100% of its power requirements from APCO. Atmos Energy, Piedmont Natural Gas (PNG), and Chattanooga Gas (CG) utilize riders related to gas procurement, capacity management and release, off-system sales, capacity assignment, and large-usage customers that contain certain incentive provisions.	No	No
Texas	For electric utilities that have not implemented retail competition, fuel and purchased power costs are recovered through a separate fuel factor, the level of which is established in base rate cases. Between base rate cases, the fuel factor may be adjusted, following hearings, based on projected fuel costs for the period the fuel factor will be in effect, subject to true-up. Capacity costs associated with purchased power are recovered through base rates, while energy costs are reflected in the fuel factor. Under- or over recoveries are deferred, with interest, for recovery over a subsequent 12 month period. El Paso Electric (EPE), Southwestern Public Service (SWPS), Southwestern Electric Power (SWEPCO), and Entergy Texas (ET) have not implemented retail competition, and continue to operate under the fuel factor mechanism. For utilities that implemented retail competition, AEP Texas Central (TCC), AEP Texas North (TXN), CenterPoint Energy Houston Electric (CEHE), Oncor Electric Delivery, and Texas-New Mexico Power (TNMP), during the transition period, price-to-beat rates charged by the affiliated retail electric providers (REPs) were permitted to be adjusted up to twice annually to reflect changes in prices of natural gas and purchased energy (see the Electric Regulatory Reform/Industry Restructuring section). Now that the transition period has ended, all customers' prices are set essentially at the REPs' discretion. A REP must notify customers 45 days prior to a price change.	Restructured state. Full pass through without incentives.	Restructured state. 100% pass through without risk-sharing.
Utah	Legislation enacted in 2009 granted the PSC the authority to allow electric and gas utilities to implement balancing accounts to recover purchased power and fuel costs. We note that the PSC had authorized such mechanisms in the past, despite the lack of specific statutory authority to do so. In addition, in lieu of a fuel adjustment mechanism, the PSC previously permitted PacifiCorp to implement temporary base rate increases to recover increases in purchased power costs. Effective Sept. 21, 2011, the PSC authorized PacifiCorp to implement a four-year pilot energy balancing account (energy cost recovery mechanism) that contains incentive provisions. In addition, PacifiCorp operates under a separate renewable energy credit (REC) mechanism through which the company tracks variations in REC revenues from the base level established in the most recent general rate case, with any differences to flow to or be recovered from customers via an annual credit or surcharge.	No	Yes - for Pacificorp, incremental variations in actual net power costs from the baseline are allocated 70% to ratepayers and 30% to shareholders
Vermont	Power cost adjustment (PCA) and purchased gas adjustment (PGA) mechanisms are permitted, provided that such mechanisms are part of an overall alternative regulation plan (ARP). Green Mountain Power (GMP) has a PCA in place that allows for rates to be adjusted on a quarterly basis to recover from, or flow through to customers, 90% of power cost variances that exceed $0.615 million per quarter and the full amount of transmission and capacity costs that vary from amounts included in rates.	No	Yes - depending on utility. Green Mountain Power has a mechanism where 90% of variances exceeding $0.615 million on a quarterly basis are flowed to customers
Virginia	Electric fuel adjustment clauses (FACs) and purchased gas adjustment (PGA) provisions are permitted. State law also permits recovery of various other costs through adjustment mechanisms. FAC proceedings--The SCC's FAC procedure provides for electric rates to be reset annually on the basis of projected usage and costs. The utilities maintain accounts for any over- or under accruals, and these balancing accounts are reconciled through the following year's fuel factor. Purchased power energy and capacity charges for "economy" purchases are included in the fuel factor calculation. Energy charges associated with reliability purchases may flow through the fuel factor, but capacity charges are recovered through base rates.	No	No
Washington	Until 2002, power cost adjustment mechanisms (PCAMs) were not in effect, and the electric utilities were at risk for fluctuations in fuel and purchased power costs between rate cases. However, in certain cases prior to the establishment of PCAMs, the WUTC permitted the deferral of power costs that were in excess of the level being recovered through base rates. As part of a general rate case, in 2002, the WUTC approved an Energy Recovery Mechanism (ERM) for Avista Corporation that allows the company to adjust rates to reflect changes in power supply-related costs. The ERM has been modified since its inception, and now provides for 75% of any energy cost savings flow to customers and 25% to the company when annual power costs are between $4 million and $10 million lower than those included in base rates. Equal sharing is to occur between $4 million and $10 million when actual power costs are greater than the amount included in base rates. Any differences in excess of $10 million are to be allocated 90% to customers and 10% to shareholders. As recently modified in a Dec. 26, 2012 approved settlement, the ERM contains an adjustment trigger under which a surcharge or rebate occurs when the ERM balance reaches $30 million. Previously, the adjustment trigger was set at 10% of base revenues (about $45 million). A PCAM was implemented in 2002 for Puget Sound Energy (PSE) following a settlement. The PCAM allows for variations in power costs to be apportioned, on a graduated scale, between the company and customers. Specifically, if power costs are above (or below) the PCAM baseline amount, PSE is to absorb (or retain) the first $20 million above (or below) the baseline, 50% of the next $20 million, 10% of the next $80 million, and 5% of any amount that exceeds $120 million. A PCAM rate surcharge/credit is to be implemented when the deferred power cost balance reaches ±$30 million. We note that PacifiCorp does not have a power cost adjustment mechanism in place.	No	Yes - For Puget Sound Energy, the PCAM allows for variations in power costs to be apportioned, on a graduated scale, between the company and customers. Specifically, if power costs are above (or below) the PCAM baseline amount, PSE is to absorb (or retain) the first $20 million above (or below) the baseline, 50% of the next $20 million, 10% of the next $80 million, and 5% of any amount that exceeds $120 million. A PCAM rate surcharge/credit is to be implemented when the deferred power cost balance reaches ±$30 million. For Avista Corporation, 75% of any energy cost savings flow to customers and 25% to the company when annual power costs are between $4 million and $10 million lower than those included in base rates. Equal sharing is to occur between $4 million and $10 million when actual power costs are greater than the amount included in base rates. Any differences in excess of $10 million are to be allocated 90% to customers and 10% to shareholders. As recently modified in a Dec. 26, 2012 approved settlement, the ERM contains an adjustment trigger under which a surcharge or rebate occurs when the ERM balance reaches $30 million. There is no PCA for Pacificorp.

Jurisdiction	Description	Are incentives built into the FAC?	Is utility exposed to risk sharing for factors outside of its control ?
West Virginia	Electric fuel and/or purchased power costs may be recovered through either a fuel adjustment clause (FAC) or an expanded net energy cost (ENEC) factor. In addition to fuel costs, the ENEC reflects the energy portion of purchased power costs, the net benefit associated with affiliated and other wholesale sales, the demand portion of purchased power transactions, power pool capacity payments, and demand-related transmission costs and credits. ENEC factors are set annually based on actual data for the prior 12-month period and projected data for the prospective 12 months. Over- or under-recoveries are deferred for reconciliation as part of the next ENEC proceeding, with no carrying charges on the deferred balance. ENEC proceedings are typically completed within four months of filing. In accordance with a 1999 settlement and PSC order, the ENECs for Appalachian Power (APCO) and Wheeling Power (WP) were suspended; the PSC subsequently adopted a comprehensive multi-year rate settlement that called for APCO's ENEC to be reinstated effective July 1, 2006.	No	No
Wisconsin	Under the PSC's electric fuel rules, each utility forecasts monthly and annual fuel and purchased power costs on a prospective basis. If a company's actual fuel and purchased power costs are outside a monthly or cumulative monthly variance range around the forecasts, and the utility can demonstrate that these costs will likely be outside the annual range, the PSC may conduct a hearing to establish new rates. Currently, the annual variance range is plus or minus 2%. An electric utility is permitted to defer any fuel costs that are outside of its annual, symmetrical variance range for subsequent recovery or refund. However, the utility is prohibited from recovering deferrals if the company is found to be earning in excess of its authorized equity return.	No	No
Wyoming	Historically, recovery of electric fuel and purchased power costs had been addressed in base rate cases; however, PacifiCorp, and Cheyenne Light, Fuel & Power (CLF&P) now recover power costs through an energy cost adjustment mechanism, and a power cost adjustment mechanism, respectively. These mechanisms contain incentive provisions (for additional information regarding these mechanisms, see the Alternative Regulation section). In addition, MDU Resources collects from/credits to ratepayers variations in fuel and purchased power costs that deviate from an established base level through a power supply cost adjustment mechanism.	No	Yes - for Cheyenne Light, Fuel, and Power, deviations from the base level are allocated 85% to ratepayers and 15% to shareholders. For Pacificorp, deviations are allocated 70% to ratepayers and 30% to shareholders.

Notes:

1 Descriptions for the fuel adjustment clauses were obtained from Regulatory Research Associates (RRA), a division of SNL Energy. Assessment of whether these fuel adjustment clauses contain incentives or risk-sharing provisions is NERA's evaluation.

Electric Utility Generation by Fuel Source - Average of 2012 and 2013 ('000 MWh)

State	Coal	Petroleum Liquids	Natural Gas	Nuclear	Hydro Conventional	Hydro Pumped Storage	Other	Wind	Biomass	Geothermal	Solar	Percent Petroleum or Natural Gas
Idaho[1]	0	0	2,596	0	10,020	0	0	2,218	145	89	0	17.23%
Missouri	74,503	74	5,261	9,543	964	165	18	1,207	56	0	0	5.81%
Montana	14,338	13	446	0	10,618	0	337	1,462	0	0	0	1.68%
Oregon	3,197	6	12,835	0	36,434	0	43	6,898	340	96	11	21.45%
Utah	32,186	37	6,066	0	688	0	3	620	59	342	1	15.26%
Vermont	0	3	3	4,918	1,208	0	0	173	402	0	11	0.09%
Washington	5,216	12	8,091	8,898	83,684	26	72	6,805	461	0	1	7.15%
Wyoming	44,504	44	46	0	801	0	0	4,392	0	0	0	0.18%
Hawaii	1,428	7,114	0	0	36	0	115	439	26	268	17	75.36%

Notes and Sources:

Data obtained from the Energy Information Administration. Includes utility-owned generation and IPPs.

[1] Although Idaho Power does own shares of coal-fired power plants, those facilities are located outside the State.

Docket No. UE 323
Exhibit PAC/408
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Reply Testimony of Michael G. Wilding

Staff Response to PacifiCorp Data Request 4

July 2017

Date: June 29, 2017

TO: Matt McVee
PacifiCorp
825 NE Multnomah
Portland OR 97232

FROM: Lance Kaufman
Senior Economist
Energy Rates, Finance and Audit Division

OREGON PUBLIC UTILITY COMMISSION
<u>Docket No. UE 323 – PacifiCorp's First Set Data Request No 04.</u>

<u>Data Request No 04.</u>:

4. Please refer to Staff Exhibit 200, opening testimony for Dr. Lance Kaufman, page 19, Line 22. Please provide the detail calculation in excel spreadsheet format for the DA/RT adjustments of [redacted]

<u>Staff Response No 04</u>:

4. This value is the difference between PacifiCorp's net market transactions valued at the average price and PacifiCorp's market transactions valued at actual price. See Staff/200, Kaufman/19 line 23 to Staff/200, Kaufman/20 line 1. Staff calculated this value using the following formula:

$$\frac{Average\ Market\ Price}{Average\ PacifiCorp\ Price} * Net\ Transaction\ Value$$

Staff notes at Staff/200, Kaufman/16 that the ratio of Average Market Price to Average PacifiCorp Price is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] This results in an adjustment of [BEGIN CONFIDENTIAL] $[redacted] [END CONFIDENTIAL]. See the file produced in response to PacifiCorp DR 2 named "UE 323 Staff Response to PAC DR 02 Attachment 1 CONF.xlsx" for the excel spreadsheet format of this calculation. Furthermore, as noted in Staff's testimony, Staff's recommended adjustment was a preliminary estimate. Staff/200, Kaufman/19. My testimony was intended to reflect a methodology for calculating the adjustment, rather than a final recommendation. In preparing a response to this data request, I have further refined my calculation to reflect the lower average market price of [BEGIN

CONFIDENTIAL] $23.18 per MWh [END CONFIDENTIAL] which produces a value of [BEGIN CONFIDENTIAL] $[redacted] [END CONFIDENTIAL].

Docket No. UE 323
Exhibit PAC/409
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

Staff Response to PacifiCorp Data Request 5

July 2017

Date: June 29, 2017

TO: Matt McVee
PacifiCorp
825 NE Multnomah
Portland OR 97232

FROM: Lance Kaufman
Senior Economist
Energy Rates, Finance and Audit Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 323 – PacifiCorp's First Set Data Request No 05.

Data Request No 05.:

5. Please provide the detail calculation in excel spreadsheet format to support the step by step analysis on Page 22, Line 5-23 of Staff Exhibit 200, opening testimony for Dr. Lance Kaufman.

Staff Response No 05:

5. Step 1: See Staff/200 workpaper "_ORTAM18 NPC Study CONF Base.xlsx" sheet named "GRID Thermal Gen by Unit (MWH)". Staff's selection of low usage months was intuitive and did not utilize a specific threshold. Staff's analytic approach is a manual process that is similar to a generic iterative optimization algorithm which modifies the model inputs and compares the minimand to the original. Staff concedes that alternate shutdown plants and periods may result in lower net power costs than the scenario selected by Staff because Staff only evaluated two shutdown scenarios. See Staff/200 Kaufman/23 at lines 8 to 12.

   Step 2: See Staff/200 workpaper "_ORTAM18 NPC Study CONF Base.xlsx" sheet named "GRID Fuel Price ($MMBtu)". Staff's selection of high fuel cost coal plants was intuitive and did not utilize a specific threshold. Staff's analytic approach is a manual process that is similar to a generic iterative optimization algorithm which modifies the model inputs and compares the minimand to the original. Staff concedes that alternate shutdown plants and periods may result in lower net power costs than the scenario selected by Staff because Staff only evaluated two shutdown scenarios. See Staff/200 Kaufman/23 at lines 8 to 12.

   Step 3: See Staff/200 workpapers "EOR JB1 60.csv" and "EOR JB1 60 CH 60.csv".

Step 4: See Staff/200 workpapers “EOR JB1 60.csv” and “EOR JB1 60 CH 60.csv”.

Step 5: See Staff/200 workpapers contained in the subfolders named “_ORTAM18 NPC Study_2017 03 21 JB60” and “_ORTAM18 NPC Study_2017 03 21 JB60CH60”.

Step 6: See Staff/200 workpapers “_ORTAM18 NPC Study CONF_ JB.xlsx” and “_ORTAM18 NPC Study CONF_ JB_CH.xlsx”.

Step 7: See Staff/200 workpapers “_ORTAM18 NPC Study CONF_ JB.xlsx” and “_ORTAM18 NPC Study CONF_ JB_CH.xlsx” at sheet NPC row 277.

Docket No. UE 323
Exhibit PAC/410
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

CUB Response to PacifiCorp Data Request 2

July 2017

Oregon Citizens' Utility Board
610 SW Broadway, Suite 400
Portland, OR 97205
(503) 227-1984
www.oregoncub.org

June 26, 2017

Via Huddle

Matthew McVee
PacifiCorp
825 NE Multnomah
Portland, OR 97232

**RE: In the Matter of PACIFICORP, dba PACIFIC POWER
2018 Transition Adjustment Mechanism ("TAM")
Docket No. UE 323**

Dear Mr. McVee:

Enclosed please find the Oregon Citizens' Utility Board's (CUB) responses to PacifiCorp's data requests in the above-referenced docket.

If you have any questions, please do not hesitate to call.

Sincerely,

Michael P. Goetz, OSB #141465
Staff Attorney
Oregon Citizens' Utility Board
610 SW Broadway, Ste. 400
Portland, OR 97205
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E. mike@oregoncub.org

DATA RESPONSES

1***. Refer to CUB/100, Jenks/5: Please provide all analysis and support for the conclusion that "PAC would still have Bridger 3 and 4 operating in 2018" if the selective catalytic reduction systems had not been installed.***

CUB's testimony referenced CUB's Confidential Comments in LC 57 which was CUB's analysis of PacifiCorp's IRP analysis of the plant. In that IRP, PacifiCorp provided a confidential study of its coal investments, and CUB's analysis was provided in response to that confidential study. A redacted version is available at http://edocs.puc.state.or.us/efdocs/HAC/lc57hac82941.pdf. Please see pages 7 to 20 for CUB's analysis of the SCR investment at issue here. The unredacted analysis is subject to the protective order in that docket (OPUC Order No 13-095).

PacifiCorp has not asked for a prudence review of the Bridger investment. Therefore, PacifiCorp has not updated its analysis of the investment and CUB has not updated its criticism of the investment.

But one key to our criticism was that the EPA would likely agree to allow the plants to operate for several years without an SCR if the Company committed to phasing the plants out. In 2010, for example PGE proposed shutting down Boardman in 10 years as an alternative to investing in pollution control.

CUB believes that PacifiCorp could have kept the plant open longer than its IRP analysis considered; that this would have resulted in a lower cost alternative to the SCR investments; and that the retirement dates would have been after the 2018 test year. Under this scenario, there would be no SCRs on the plants and they would still be operating today.

It should be noted that in LC 62, and LC 67, PacifiCorp modeled SCR alternatives which included the kind of longer phase out periods that CUB advocated in LC 57 with the modeling showing that avoiding an SCR with a longer phase out was generally the least cost approach. CUB believes this analysis, also confidential, is consistent with the position we took in LC 57 and in this docket.

2. Refer to CUB/100, Jenks/10:

a. Has CUB performed any calculations related to its proposed Contract Delay Rate (CDR)? If so, please provide those calculations. If not, please provide a detailed example demonstrating how the CDR would be calculated.

CUB proposed a general methodology for improving the forecasting of the Commercial Operation Date (COD) date for new QFs. CUB did not proposal a single specific methodology. CUB hopes to discuss this during settlement and will be informed by the Company's Reply

Testimony. After the input of settlement and Reply Testimony data, CUB expects to propose a specific methodology in Rebuttal Testimony.

Currently CUB envisions a methodology along the following lines.

1. For the most recent three TAMs, identify all new QFs that were expected to have a COD after the final update used for ratemaking purposes.
2. For each individual project identify the number of days that the QF's COD was delayed or was early as compared to the final update.
3. Add up the total number of days of COD delays, and subtract the total number of days of early COD.
4. Divide this number by the total number of projects to get the average Contract Delay Rate (in days of delay).
5. Apply this CDR to all new projects with COD after the final update

b. Has CUB performed any analysis demonstrating that the application of its proposed CDR would result in a more accurate forecast of total QF costs? If so, please provide that analysis.

No. CUB did not look at whether our proposal would result in a more accurate forecast of total QF costs because CUB's proposal did not deal with total QF costs. CUB's proposal was designed to address a narrow subset of QFs, those with a COD after the final update. CUB's Opening Testimony (pages 8 and 9) demonstrate that the current methodology is not accurately forecasting when PacifiCorp will begin receiving power from new QFs. CUB was attempting to create a more accurate forecast of this subset of QFs.

CUB is not challenging PacifiCorp methodology for forecasting QF costs once those QF's have achieved commercial operation. Currently, CUB is not aware of any significant forecast errors associated with QFs that have already reach COD.

Docket No. UE 323
Exhibit PAC/500
Witness: Kelcey A. Brown

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Kelcey A. Brown

July 2017

REPLY TESTIMONY OF KELCEY A. BROWN

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Q. Please state your name, business address and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp).

A. My name is Kelcey A. Brown. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present title is Director, Market Policy and Analytics.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have been employed by PacifiCorp since May 2011. I have been the Director of Market Policy and Analytics since July 2015. My responsibilities at PacifiCorp are primarily related to the Energy Imbalance Market (EIM). My group is responsible for submitting bids and resource schedules to the California Independent System Operator (CAISO) on a daily basis, scheduling resource outages, reviewing actual EIM operations on a daily basis, and the calculation of EIM benefits. As stated by several parties in this proceeding, the EIM is a complex operation that produces large amounts of data that PacifiCorp must monitor and utilize to ensure that its resource schedules are correct, bid prices accurately reflect the cost of operation, and resources are dispatched accordingly.

Before that time, I worked as the Manager of Load Forecast and as a Senior Consultant in the Regulatory Net Power Costs Department. Before joining PacifiCorp, I worked at the Public Utility Commission of Oregon (Commission) from November 2007 through May 2011. During my time at the Commission, I sponsored testimony in several dockets involving net power costs, integrated resource planning, and various revenue and policy issues. From 2003 through 2007, I was the Economic

Analyst with Blackfoot Telecommunications Group, where I was responsible for revenue forecasts, resource acquisition analysis, pricing, and regulatory support. I have a Bachelor of Science degree in Business Economics from the University of Wyoming, and I have completed all course work towards a Master's degree in Economics from the University of Wyoming.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support PacifiCorp's estimation of the EIM benefits for calendar year 2018 and respond to Commission Staff witness Mr. Scott Gibbens' testimony, specifically concerns that PacifiCorp's methodology for estimating inter-regional dispatch EIM benefits does not account for an historical upward trend and "relies too heavily on the assumption that the benefits are stationary."[1] My testimony also shows that the more recent upward trend in EIM benefits was driven by the unique attributes of new entrants and is not likely to continue at the same rate.

Q. Please summarize your testimony.

A. PacifiCorp's reply update forecast of inter-regional EIM benefits is reasonable and consistent with the methodologies that the Commission has approved in prior Transition Adjustment Mechanism (TAM) cases. The forecast relies on the most recent validated six months of actual historical data annualized to reflect a full year of benefits. The historical period used in PacifiCorp's forecast reflects the latest participants in the EIM, operational changes made at the company's plants to better

[1] Staff/100, Gibbens/8, lines 12-13.

achieve EIM benefits, and changes made by CAISO to EIM operations. The company's forecast includes a reasonable growth rate that is based on historical data, adjustments for new entrants in 2017 and 2018, continued solar penetration in California and takes into consideration the market dynamics that will limit future growth in EIM benefits. By relying on the most recent validated operational data, PacifiCorp's forecast reflects the level of benefits that the company can reasonably expect in 2018.

Staff's recommendation to impute additional inter-regional benefits is unreasonable. Staff's adjustment applies an arbitrary growth rate that relies on outdated historical data and fails to consider how changes in the EIM market will limit the growth in PacifiCorp's inter-regional EIM in 2018, as compared to previous years.

PACIFICORP'S CALCULATION OF EIM BENEFITS

Q. What are the inter-regional dispatch EIM benefits and how does PacifiCorp forecast them?

A. Inter-regional EIM benefits result from economic transactions between PacifiCorp and other EIM participants. In the initial filing, the company forecasted benefits for 2018 based on its actual calendar year 2016 benefits, adjusted to reflect the full participation of NV Energy (NVE), Arizona Public Service (APS), Puget Sound Energy (PSE), and Portland General Electric (PGE). PacifiCorp's forecast also accounted for the additional participation of Idaho Power Company (IPC), which is expected to join the EIM in 2018. The methodology used for the initial filing was largely the same as the 2016 and 2017 TAMs[2] and resulted in a forecasted EIM inter-regional benefit of $24.4 million, total-company.

Q. Do you agree with Staff that there is an historical upward trend in actual EIM benefits?

A. Yes. I agree with Staff that from January 2014 through March 2017 there is an upward trend in actual EIM benefits. As discussed more fully below, however, the rate at which EIM benefits accrue is not likely to follow the same upward trend observed between January 2014 and March 2017. Consistent with that observation, PacifiCorp updated its forecast EIM benefits in each TAM reply update since the inception of the EIM to reflect the most recent information and changes in the market.

Q. Can you please summarize the change in EIM benefits from the initial filing?

A. Yes. PacifiCorp's estimated EIM benefits for 2018 have been updated to include the most recent validated information through March 2017, as well as expectations associated with additional entrants and market policy changes at the CAISO associated with greenhouse gas (GHG) accounting changes. The total expected EIM benefits are shown in Confidential Table 1 below:

CONFIDENTIAL TABLE 1

2018 TAM EIM Benefit	Initial TAM EIM Benefits	Updated TAM EIM Benefits
EIM Inter-regional Benefit	[redacted]	[redacted]
GHG EIM Benefit		
Total EIM Benefit*	$24,357,321	$34,999,827

* Total EIM Benefit does not include diversity reserve benefit.

[2] As described in the initial filing, PacifiCorp did make one modification to account for an issue CUB raised in the 2017 TAM. PAC/100, Wilding/28.

Q. PacifiCorp's expected EIM benefits for 2018 increased by $10.6 million; please explain your forecast methodology and the increase in the benefits relative to the initial filing.

A. In the reply update, PacifiCorp included forecast EIM inter-regional benefits of [redacted] for 2018. The forecast benefits represent a compound annual growth rate of 32 percent relative to 2016 actual EIM benefits. PacifiCorp's forecast utilized average historical EIM benefits from October 2016 through March 2017 to forecast calendar year 2018. The time period used in the forecast data set took into consideration changes in the market as of October 2016 with the introduction of APS and PSE. In addition, the CAISO introduced new requirements for flexible ramping that included a flexible ramp down requirement that requires PacifiCorp to show a sufficient amount of down ramping capability before each hour. Although the company used less historical data to estimate the reply update benefits, the six months used are more representative of the market in 2018.

Q. Why does each new EIM entity have an impact on the actual and expected EIM benefits for PacifiCorp?

A. Each new EIM entity adds additional transmission and a unique resource portfolio that allows the market to take advantage of regional diversity in loads and resources, such as higher loads in the Desert Southwest in late summer versus lower loads in the Pacific Northwest and Rocky Mountain region. PacifiCorp's EIM benefits are based on its ability to import power and avoid more expensive generation or export power and be paid a price above its generation cost within the operating hour. Each new entity has caused a change in EIM benefits that are unique to what that entity brought to the market, *e.g.*, transmission capacity, intertie points, thermal resource stack, and variable resource portfolio.

Q. Can you please discuss the changes in EIM benefits when NVE joined the EIM.

A. NVE joined the EIM on December 1, 2015, and PacifiCorp realized an increase in its volume of imports and exports in the market due to its transmission interconnection with NVE of approximately 700 MW and NVE's transmission interconnection to CAISO at Eldorado of approximately 800 MW. PacifiCorp's EIM benefits grew, year-over-year, by approximately 56 percent, due primarily to the entrance of NVE, as well as PacifiCorp's ability to more efficiently optimize its operations in the market.

Q. Did PacifiCorp see similar changes in EIM benefits with the additions of APS and PSE into the EIM?

A. Yes. However, PacifiCorp also made a multitude of operational changes at its coal facilities at the end of 2016 that increased the flexibility of its resources relative to the prior year. For example, PacifiCorp removed the configurations and transition times at many of its coal facilities and lowered its minimum operating parameters to take greater advantage of lower priced renewable energy available in the market.

Q. Why doesn't PacifiCorp utilize the 56 percent growth rate in EIM benefits that was realized from 2015 to 2016 to forecast its 2018 benefits?

A. PacifiCorp's growth in EIM benefits in the initial phases of the EIM was due to additional transmission that allowed the company to continue to utilize the flexibility in its resource portfolio. As additional entrants join the market, however, PacifiCorp has less capability to capture additional benefits due to its inability to move its resources more than it does today. It is becoming clear, with the introduction of APS and its additional transmission interconnection of approximately 600 MW, that there is a point of saturation relative to the additional benefits that the company can achieve due to resource limitations.

Q. Why does PacifiCorp face resource limitations when it comes to realizing additional EIM benefits?

A. As stated previously, PacifiCorp is able to realize EIM benefits through the optimization of its resources. For example, if prices in the EIM are $5 per MWh, then all of PacifiCorp's participating resources will be decremented, subject to ramp rates, to take advantage of the cheaper power. At a certain point, however, each resource will hit its minimum operating level. When that occurs, PacifiCorp is unable to realize additional market imports. While the example is simplistic, it is becoming more obvious that PacifiCorp's resource capability to take advantage of additional EIM benefits is becoming saturated.

Q. If PacifiCorp is limited by its resource flexibility, why doesn't it simply schedule fewer resources for the operating hour to take advantage of lower cost renewable energy imports through the EIM?

A. The EIM is designed such that each EIM entity is required to be self-sufficient, as if the market did not exist, to prevent leaning on the market by an entity, which includes going into the operating hour with too much capacity as well as going into the operating hour with too little capacity to meet the projected demand for the hour. For example, PacifiCorp must schedule its resources to meet expected demand within one percent of the forecast load, it must have enough capacity available to the market to meet expected changes in load and variable energy output, and it must have enough capacity to meet any unexpected changes in load and variable energy resource output (uncertainty). Due to these requirements, PacifiCorp can be limited in the amount of flexibility it has going in to each operating hour.

Q. Is it possible that new entrants may decrease PacifiCorp's EIM benefits in the future?

A. Yes. If a new EIM entrant provides a load or resource diversity that is complimentary to the current resource mix in the market, it would allow the market to take advantage of that diversity without utilizing PacifiCorp's resources. For example, if a renewable resource in California decreases by 200 MW and simultaneously a renewable resource in Idaho increases by 200 MW, market prices are unchanged and PacifiCorp's resources would not be dispatched as compared to today.

Q. You noted above that PacifiCorp was able to make changes in the modeling and operation of its resources in 2016. Do you expect to make similar changes in 2017 that would allow EIM benefits to continue to grow at the same annual rate?

A. No. The changes made at the PacifiCorp coal generation facilities were completed in late 2016 and early 2017 on the units that had the capability to operate without transition times and at lower minimum operating levels. Additional flexibility at the coal units would likely require significant capital investment or it is operationally infeasible due to environmental requirements at the facility site. The increased benefits associated with these changes is built into the company's updated EIM benefit forecast.

Q. PacifiCorp utilizes an official forward price curve for purposes of forecasting its net power costs. Is there an official forward price curve for the EIM that can be utilized to forecast PacifiCorp's EIM benefits?

A. No. There is no forward price curve for the EIM, nor are there day-ahead prices or even hour-ahead prices for an intra-hour market because the market price will vary based on five and 15-minute changes in load and variable energy resources.

Q. You show a change in the expected GHG revenues received by PacifiCorp in 2018; can you please explain the change?

A. Yes. California's GHG policies provide PacifiCorp's hydro facilities the opportunity to provide emission-free energy to California and earn marginal GHG revenue. There has been an increase in GHG revenues associated with PacifiCorp's hydro generation over the last two years due to increased transfer volumes to the CAISO as the EIM has continued to expand. [redacted].

RESPONSE TO STAFF'S ADJUSTMENT

Q. What is the basis for Staff's proposed adjustment to inter-regional EIM benefits?

A. As noted above, Staff argues that PacifiCorp's calculation of the inter-regional EIM benefits improperly relies on only historical data and does not build sufficient growth into the benefits that are anticipated for 2018. Staff recommends that the Commission apply a growth rate to the EIM benefits equal to 50 percent of the year-over-year growth rate for inter-regional benefits, based on the most recent 12 months of available data. The application of Staff's proposed growth rate would increase the inter-regional EIM benefits by 66 percent, or $16.2 million, total-company.[3]

Q. Do you agree with Staff's recommendation to increase the inter-regional EIM benefits by $16.2 million relative to PacifiCorp's initial filing?

A. No. While I understand Staff's concern that PacifiCorp's initial filing did not appear to forecast sufficient EIM benefits relative to more recent actual EIM benefits, the methodology that Staff used to change PacifiCorp's forecast is not consistent with the underlying fundamentals of what drives growth in EIM benefits. By simply using a historical growth rate, and arbitrarily cutting it in half, it ignores what actually drove changes in the EIM benefits and whether or not those changes can be repeated with similar results. As I discuss above, the growth rate from 2015 to 2016, which formed much of the basis for Staff's adjustment, is not likely to be replicated going forward. Moreover, PacifiCorp's updated EIM benefits reflect substantial growth over historical forecasts.

Q. You state above that the year-over-year growth of EIM benefits from 2015 to 2016 was 56 percent, which seems inconsistent with Staff's calculation of year-over-year growth of approximately 133 percent.[4] Did you utilize different actual EIM benefit results?

A. No. The 56 percent annual growth rate of EIM benefits for 2015 versus 2016 utilized actual EIM benefits. But instead of using a monthly growth calculation and then

[3] Staff/100, Gibbens/11-12.
[4] Staff/200, Gibbens/11.

averaging the monthly growth rates to calculate an annual growth rate, as Staff did, I used the more common practice of using calendar year 2016 actuals versus calendar year 2015 actuals minus one to calculate the annual growth rate.

$$\frac{\text{2016 Annual Value}}{\text{2015 Annual Value}} - 1 = \%\ \text{Growth Rate}$$

In addition, Staff erroneously calculated its growth rate using the previous 16 months of historical data, not the 12 months described in its testimony. Using Staff's methodology, the comparable growth rate would have been 144 percent. Correcting this error reduces Staff's adjustment by $1.2 million.

Q. Is it reasonable to use an average of the monthly growth rates to calculate a total annual growth rate?

A. No. Staff's methodology significantly overstates the annual growth rate of the EIM benefits.

Q. Does Staff's calculation have any other errors?

A. Yes. Staff calculated its monthly growth figure on the inter-regional benefits only, but applied its growth rate to the GHG component, which overstates its adjustment by [redacted].

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 323
Exhibit PAC/600
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Dana M. Ralston

July 2017

REPLY TESTIMONY OF DANA M. RALSTON

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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)?

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 PacifiCorp'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 Staff (Staff) witness Dr. Lance Kaufman on June 9, 2017, proposing an adjustment to the amount of liquidated damages at the Cholla plant.

Third, I respond to the testimony of Sierra Club witness Dr. Thomas Vitolo. I address Sierra Club's claim that the Naughton plant was dispatched non-economically in 2015 and 2016, and its adjustment to 2018 rates to account for the allegedly non-economic dispatch in 2015 and 2016. I also respond to Sierra Club's general criticisms of PacifiCorp's coal plant modeling and dispatch.

PacifiCorp's expert witness, Mr. Seth Schwartz, President of Energy Ventures Analysis (EVA),[1] provides testimony addressing the prudence of the Company's multi-year coal supply contracts in response to testimony from Staff and Sierra Club. PacifiCorp witness Mr. Michael G. Wilding addresses the modeling of these contracts in the 2018 TAM.

[1] EVA is listed among the Forbes Top 10 consulting firms for 2017 in the energy sector. https://www.forbes.com/best-management-consulting-firms/list/#sortreverse:true_industryRanks:Energy%20%26%20Environment

Q. Please summarize your reply testimony.

A. My testimony demonstrates that PacifiCorp's 2018 fuel strategy is prudent and results in reasonable net power costs (NPC) for customers. More specifically:

- PacifiCorp has made significant progress in negotiating an agreement with the Black Butte mine to supply coal to the Jim Bridger plant for a period of three-to-four years. The contract will address Jim Bridger's near-term fuel supply needs at a reasonable price, while providing flexibility as PacifiCorp assesses and implements a long-term fuel supply strategy for the Jim Bridger plant.
- PacifiCorp's approach to modeling liquidated damages under the Cholla coal supply agreement (CSA) ties directly to the terms of the Cholla CSA and the company's preliminary nomination for 2018 coal purchases under the CSA. Staff's adjustment is based on the incorrect premise that liquidated damages should be calculated on the higher volume of coal consumption at Cholla. This is inconsistent with the CSA and discounts the company's reasonable use of its current coal inventory for a portion of Cholla plant's coal supply in 2018.
- PacifiCorp was prudent in managing coal supply to its Naughton generation plant, including purchasing above the minimum take levels in the Naughton CSA. Sierra Club's adjustment is based on incorrect assumptions that disregard the terms of the CSA. My analysis corrects Sierra Club's assumptions and demonstrates that PacifiCorp's dispatch of Naughton was more advantageous to customers than Sierra Club's alternatives.
- Sierra Club's recommendation that the Commission preclude PacifiCorp from

entering into any future CSAs is unsupported and would increase costs and risks to customers.

TAM REPLY UPDATE TO COAL COSTS

Q. Please describe PacifiCorp's coal costs update.

A. Under the TAM Guidelines, PacifiCorp 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 2018 TAM has decreased from $807.4 million in the initial filing to $778.6 million in the reply update, which reflects a decrease of $28.9 million on a total company basis.[3] This overall decrease results from changes in both the modeled coal volumes and prices. The reply update decreased coal volumes to 20.4 million tons compared to 21.6 million tons in the initial filing. The lower coal volume reduced coal fuel expense by $19.8 million, and updated prices reduced coal fuel expense by $9.1 million.

Q. What are the primary drivers of the $9.1 million 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 [redacted] coal fuel expense reduction, primarily as a result of additional tier-2 contract priced coal purchased at Naughton, a new coal contract for the Dave Johnston plant, and updated price indices. Affiliate mine unit cost increases result in

[2] Under the TAM Guidelines, PacifiCorp files the TAM each spring, forecasting NPC for the next year. The initial filing of the TAM was filed on April 1, 2017, using a 2018 test period, so PacifiCorp refers to it as the 2018 TAM. PacifiCorp also typically refers to previous TAMs by test period, not by the year of filing.
[3] All references to costs and revenues in my testimony are on a total-company basis, unless noted otherwise.

a [redacted] coal fuel expense increase, primarily related to reduced incremental coal delivered by Bridger Coal Company (BCC).

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

A. PacifiCorp 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 2017 Request for Proposals solicitation for the Dave Johnston plant, decreased coal prices for the Naughton plant due to additional forecasted delivered coal at tier-2 contract prices, and reductions in the contract-specific producer and consumer price indices, resulting from updated price and inflation escalation assumptions. These decreases are partially offset by an increase to the updated forecast price of the pending Black Butte mine contract.

Confidential Table 1: Third-Party Coal and Transportation Contract Price

Plant	Contract	Millions ($)
Naughton	Kemmerer Coal	[redacted]
Wyodak	Wyodak Coal	
Dave Johnston	Powder River Basin Coal	
Dave Johnston	BNSF Rail	
Jim Bridger	Black Butte Coal	
Jim Bridger	UPRR Rail	
Hunter	Bowie Coal	
Huntington	Bowie and Castle Valley Coal	
Cholla	Lee Ranch Coal	
Cholla	BNSF Rail	
Colstrip	Rosebud Coal	
Hayden	Twentymile Coal and UPRR Rail	
Craig	Colowyo Coal and UPRR Rail	
Total Third-Party Contract Price Increase/(Decrease)		

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

A. In the reply update, PacifiCorp updated its Official Forward Price Curve, which decreased wholesale natural gas and electricity prices. As discussed in Mr. Wilding's reply testimony, this decrease in wholesale natural gas and electricity prices decreased coal dispatch in the reply update, resulting in less coal required at the Jim Bridger plant.

Jim Bridger Third-Party Coal Supply Update

Q. What is the basis for PacifiCorp's updated third-party coal supply costs for the Jim Bridger Plant?

A. The updated third-party coal supply costs are based on discussions between PacifiCorp and the Black Butte mine for a new, near-term coal supply contract beginning in 2018. The updated costs also reflect the most recent pricing information from the Union Pacific Railroad (UPRR).

As described in my direct testimony, PacifiCorp's current Black Butte CSA and UPRR transportation agreement both expire at the end of 2017. PacifiCorp's near-term strategy fuel strategy for the Jim Bridger plant is to arrange the least-cost, least-risk fuel supply for the next three-to-four years to allow the company to assess possible supply changes through its long-term fuel plan and implement any changes. Under this near-term strategy, PacifiCorp proposes to secure a new agreement with the Black Butte mine and related transportation from UPRR.

Q. Please describe the updated third-party coal prices for the Jim Bridger plant.

A. Based on current negotiations with Black Butte and the volume and contract length expected to result, the updated third-party coal prices include a price of [redacted] per ton for 2018, which is a [redacted] percent increase from the 2017 price of [redacted] per ton. In the initial filing, PacifiCorp had estimated a price of [redacted] per ton for 2018, which is an [redacted] percent increase from the 2017 price. The slight increase in the projected price is a result of the current discussions with Black Butte. The updated transportation price has decreased by [redacted] per ton from [redacted] per ton to [redacted] per ton.

Q. When does PacifiCorp expect to execute the third-party coal supply and transportation agreements for the Jim Bridger plant?

A. PacifiCorp expects to finalize term sheets with both Black Butte and UPRR before its surrebuttal testimony is filed on August 11, 2017.

STAFF'S COAL PRICE ADJUSTMENT

Q. Please describe Staff's proposed coal price adjustment for the Cholla plant.

A. In the 2018 TAM, PacifiCorp forecasts that it will pay liquidated damages under the CSA with Peabody Energy because the volume of coal PacifiCorp will purchase is less than the liquidated damage minimum requirements in the CSA. Staff claims that PacifiCorp's calculation of liquidated damages is excessive. Staff re-calculates the liquidated damages and recommends an adjustment that reduces NPC by [redacted].[4]

Q. How did PacifiCorp calculate liquidated damages for the Cholla plant?

A. In the initial filing, PacifiCorp forecast liquidated damages of [redacted], based on the volume of projected coal purchases in 2018. The Cholla plant's liquidated

[4] Staff/200, Kaufman/27-28.

damages provision of the CSA provides that if PacifiCorp takes less than [redacted] tons of coal in a calendar year, the liquidated damages are [redacted] per ton for each of the shortfall tons. PacifiCorp forecasted [redacted] tons of coal purchases in the initial filing, which results in a shortfall of [redacted] tons and liquidated damages of [redacted].

Q. How does Staff calculate liquidated damages?

A. Staff incorrectly calculates liquidated damages based on forecast coal consumption at the Cholla plant in 2018, which is higher than coal purchases. Under the CSA, however, liquidated damages are based on the volume of coal *purchases* in 2018, not the volume of coal *consumption* in 2018.

Q. Why would the volume of coal purchases in 2018 differ from the volume of coal consumption in 2018?

A. The Cholla plant's projected coal stockpile level at January 2018 is significantly above its target level. Fluctuations in coal stockpile levels result from changes in power market supply and demand, coal market pricing, plant operational constraints and issues, and coal supplier concerns.

To reduce the coal stockpile level at Cholla, PacifiCorp intends to purchase less coal in 2018 than it will consume. For Cholla, the anticipated stockpile level at January 2018 is [redacted] tons,[5] compared to the target range of between [redacted] tons and [redacted] tons, which is based on a days-burn target of [redacted]-to-[redacted] days.

In the initial filing, PacifiCorp forecasted that the Cholla plant would consume [redacted] tons of coal. The initial filing forecast [redacted] tons of purchased coal to

[5] A description of the calculation of this estimated stockpile level is provided in my confidential workpapers provided with my direct testimony.

allow PacifiCorp to reduce the stockpile by [redacted] tons, to a level of [redacted] tons by the end of 2018. The balance of the stockpile reduction is forecast to occur in a subsequent year. If PacifiCorp were to attempt to purchase coal at its full consumption level for 2018, as assumed in Staff's adjustment, the Cholla stockpile would continue to be well above its target level. While coal stockpiles naturally fluctuate over time, PacifiCorp works to maintain target levels to avoid the incremental costs of maintaining a large stockpile, and the operational issues and risks associated with maintaining a small stockpile.

Q. Did PacifiCorp update its projected purchases under the Cholla CSA in the reply update?

A. Yes. In the reply update, the Generation and Regulation Initiative Decision Tools model calculated [redacted] tons of coal consumed at Cholla. On [redacted], PacifiCorp made its preliminary nomination under the contract [redacted]. The CSA requires a final nomination by [redacted] which may not be [redacted] greater or less than the preliminary nomination. Therefore, coal forecast to be purchased during 2018 in the reply update is [redacted] tons, resulting in liquidated damages of [redacted], a slight reduction from the initial filing. The reply update will result in a projected stockpile inventory of [redacted] tons at the end of 2018.

Q. How does PacifiCorp generally model coal stockpile levels in the TAM?

A. Working with its regulators, PacifiCorp periodically studies and sets target coal inventory levels. PacifiCorp takes these coal inventory targets into account when forecasting coal costs for the TAM. Coal stockpile levels typically remain fairly flat in the TAM as long as levels are within the targeted ranges. If the forecast beginning level is above the target, however, the stockpile is reduced to within the targeted range as soon as prudently possible, absent other operational concerns or risks. Likewise, if the beginning level is below target, the stockpile is increased.

Q. Are there other ways in which Staff's adjustment ignores the terms of the Cholla CSA?

A. Yes. Staff's adjustment assumes that PacifiCorp will purchase [redacted] tons of coal under the CSA.[6] But the amendment to the CSA signed in February 2017 states that [redacted].

SIERRA CLUB'S COAL PRICE ADJUSTMENT AND RECOMMENDATIONS

Q. Please describe Sierra Club's proposed adjustment related to Naughton coal costs.

A. Sierra Club contends that PacifiCorp dispatched the Naughton plant uneconomically from July 2015 to June 2016 because PacifiCorp improperly purchased more coal than was required by the minimum take requirement in its CSA. Sierra Club claims that if PacifiCorp had dispatched Naughton based on the minimum take levels in its CSA, PacifiCorp's NPC would have been $2.4 million lower from July 2015 to June

[6] Staff/200, Kaufman/27.

2016. Sierra Club recommends an adjustment reducing 2018 NPC by $2.4 million to account for the allegedly imprudent dispatch of Naughton from 2015 and 2016.[7]

Q. How did Sierra Club calculate the proposed $2.4 million adjustment?

A. Sierra Club created a spreadsheet dispatch model that attempts to calculate the NPC difference between operating the Naughton plant at the minimum take level of [redacted] tons consumed and the actual 2,621,207 tons consumed from July 2015 to June 2016.[8] Sierra Club's model uses actual PacifiCorp data for some of the inputs, while also making assumptions that are practical in some cases and unworkable in other cases.

Q. Is Sierra Club's adjustment reasonable?

A. No. Sierra Club's adjustment is based on erroneous coal pricing. Although Sierra Club acknowledges that many coal contracts include tiered pricing,[9] Sierra Club's modeling fails to properly account for the tiered pricing mechanism of the Naughton CSA.

Q. Please describe the tiered pricing in the Naughton CSA that was in effect from July 2015 to June 2016.

A. As stated in my Direct Testimony, the Naughton CSA includes a minimum requirement of [redacted] tons and a maximum of [redacted] tons. The first [redacted] tons are priced at a tier-1 price, and tons above that level are priced at a lower tier-2 price.[10] During the July 2015 to June 2016 contract year that is the subject of Sierra Club's adjustment, the tier-1 price was [redacted] (which applied to

[7] Sierra Club/100, Vitolo/18.
[8] Sierra Club/100, Vitolo/16.
[9] Sierra Club/100, Vitolo/11.
[10] PAC/200, Ralston/16.

the first [redacted] tons) and the tier-2 price was [redacted] (which applies to all tons in excess of [redacted] tons). Because PacifiCorp purchased 2,621,685 tons from July 2015 to June 2016, the average purchased price during that period was [redacted] per ton, as set forth in Confidential Table 2 below.

Q. How does Sierra Club's modeling fail to account for the tiered pricing in the Naughton CSA?

A. Sierra Club's modeling of the minimum take scenario (*i.e.*, the scenario that assumes PacifiCorp purchased [redacted] tons) incorrectly uses the *average* consumed cost of coal from July 2015 to June 2016 instead of the *tier-1* price for the calculation of the total coal cost. Sierra Club's error understates coal costs and thereby significantly overstates purported benefits that would have been received if PacifiCorp had purchased only [redacted] tons.

Q. What is the impact to Sierra Club's adjustment if its model is corrected to include accurate pricing?

A. With accurate pricing, Sierra Club's model shows that customers received a greater benefit from the actual Naughton dispatch as compared to the minimum take scenario. In other words, PacifiCorp's NPC would have been higher if it had purchased only the minimum take requirement.

After adjusting for the correct tiered pricing assumptions, Sierra Club's model shows that the actual Naughton plant dispatch level of 2,621,207 tons of coal burned, with 2,621,685 tons of coal purchased, results in revenue of [redacted] and coal costs of [redacted]—or a net customer benefit of [redacted]. The minimum take dispatch level of [redacted] tons results in revenue of [redacted] and coal costs of [redacted]—or a net customer benefit of [redacted], as shown in Confidential Table 2 below. Thus, using Sierra Club's own model and correcting only the tiered pricing, Confidential Table 2 demonstrates that the actual dispatch resulted in a greater customer benefit than the minimum take scenario. There is no basis for Sierra Club's claim that PacifiCorp's dispatch of the Naughton plant from July 2015 to June 2016 was uneconomic and harmed customers. On the contrary, Sierra Club's analysis verifies the prudence of PacifiCorp's historical dispatch of the Naughton plant.

Confidential Table 2: Naughton July 2015-June 2016 Coal Purchased with Tiered Prices

	Actual	Minimum-take	Optimal
Coal Burned (tons)	[redacted]	[redacted]	[redacted]
EIM Revenue	[redacted]	[redacted]	[redacted]
Coal Cost	[redacted]	[redacted]	[redacted]
Take or Pay Coal Cost - (1)	[redacted]	[redacted]	[redacted]
Coal Cost - Adjusted	[redacted]	[redacted]	[redacted]
Average Coal Cost/Ton	[redacted]	[redacted]	[redacted]
Tier 1 Coal Cost/Ton	[redacted]	[redacted]	[redacted]
Tier 2 Coal Cost/Ton	[redacted]	[redacted]	[redacted]
Revenue minus Coal Cost	[redacted]	[redacted]	[redacted]
Increased Revenue	[redacted]	[redacted]	[redacted]
Purchases	Tons	Cost/Ton	Dollars
Tier 1	[redacted]	[redacted]	[redacted]
Tier 2	[redacted]	[redacted]	[redacted]
Total/Average	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Q. Sierra Club's modeling also includes a so-called "Optimal" scenario that assumes PacifiCorp purchased [redacted] tons of coal.[11] Is this scenario realistic?

A. No. Sierra Club assumes that PacifiCorp could have obtained the same coal pricing found in the existing CSA even though the minimum take requirement would have been [redacted] lower. The economic reality is that PacifiCorp could not have obtained a CSA with a price of [redacted] per ton without a minimum take of [redacted] tons. As detailed in Mr. Schwartz's testimony, minimum take provisions in coal contracts are necessary in order to obtain multi-year contracts with favorable pricing. Without a minimum take provision of [redacted], the pricing under the CSA would have been significantly higher.

Moreover, as shown in Confidential Table 2 above, if PacifiCorp had purchased only [redacted] tons of coal and paid the liquidated damages required by the CSA, customers would have been harmed. Thus, there is nothing "optimal" about this scenario.

Q. Does Sierra Club provide any evidence supporting the assumption that a minimum take level of [redacted] tons is realistic?

A. No. On the contrary, Sierra Club concedes that it does not know if it would have been possible to obtain a CSA with a minimum take level of [redacted] tons when the Naughton CSA was negotiated in 2010.[12]

Q. Are there any other problems with Sierra Club's analysis of Naughton?

A. Yes. Sierra Club makes a model assumption that at the Naughton plant "each unit can produce power at any level between 0 MW and its generation capacity, and

[11] Sierra Club/100, Vitolo/16.
[12] Sierra Club/100, Vitolo/17.

immediately ramp up or down to a different operating level at the next time interval,"[13] which was measured in 15-minute intervals. This assumed ramp rate and minimum generation level, however, is not physically and operationally feasible, and it is unreasonable to use when analyzing a coal plant's response to changing market price signals. Typical ramp rates for coal plants range between three and five megawatts per minute from a realistic minimum load to the maximum load. Additional time and startup fuel would be required to startup from zero megawatts to minimum load.

Q. Does Sierra Club's adjustment raise other general concerns?

A. Yes. Sierra Club proposes to adjust rates in 2018 based on its claims that PacifiCorp imprudently managed its coal supply to the Naughton plant in 2015-2016. Sierra Club's adjustment violates the standard regulatory principle that rates are set on a prospective basis only.

Q. Sierra Club also recommends that the Commission order PacifiCorp to refrain from entering into any new CSAs until the Commission can review whether the CSAs are effecting economic dispatch.[14] How do you respond to this recommendation?

A. The Commission should reject this recommendation. First, as discussed above, Sierra Club has not presented any evidence that PacifiCorp's CSAs have resulted in uneconomic coal plant dispatch or otherwise harmed customers. Thus, there is no evidentiary basis for this extreme recommendation.

[13] Sierra Club/100, Vitolo/12.
[14] Sierra Club/100, Vitolo/3.

Second, Sierra Club's proposed prohibition on new contracts will harm customers. As described above, PacifiCorp will soon finalize a CSA with the Black Butte mine for the Jim Bridger plant. If PacifiCorp is prevented from executing that CSA, as Sierra Club recommends, then the Jim Bridger plant will have very limited access to third-party coal. PacifiCorp cannot increase production at the Bridger Coal Company mine to replace all of the volume that is forecast to be supplied by Black Butte. Without the Black Butte contract, the Jim Bridger plant will be uneconomically curtailed for lack of coal supply. This would increase NPC and harm customers.

Q. Regarding the Black Butte mine contract, Sierra Club claims that PacifiCorp has not demonstrated that a new contract is more favorable than reducing generation or closing a unit.[15] Is this correct?

A. No. PacifiCorp performs precisely this type of analysis as part of its integrated resource plan (IRP) process. PacifiCorp's 2017 IRP supports continued operation of all units at the Jim Bridger plant for the three to four-year period covered by the proposed CSA with the Black Butte mine.[16] In addition, as explained above, the relatively short-term nature of the new Black Butte contract (i.e. three-to-four years) gives the company flexibility to develop and implement a comprehensive long-term fuel strategy for the Jim Bridger plant that considers all economic variables.

Q. Is PacifiCorp doing anything else to address Sierra Club's concerns with coal plants?

A. If the continued operation of a coal unit is selected as part of the preferred portfolio in

[15] Sierra Club/100, Vitolo/7.
[16] PacifiCorp 2017 Integrated Resource Plan Volume I at 6 (Apr. 4, 2017).

the IRP, then PacifiCorp develops specific strategies and plans to provide the least-cost, least-risk fueling plan for each thermal generating plant. As noted above, the 2017 IRP does not indicate that the Jim Bridger plant should be shut down or significantly curtailed over the period covered by the proposed CSA. Therefore, there is no basis to assume, as Sierra Club does, that a shut-down or curtailment of the Jim Bridger plant is favorable to the proposed CSA.

In addition, specific to the Jim Bridger plant, PacifiCorp is in the process of developing a long-term fueling plan that will analyze various fueling options for the plant, including continued reliance on the Black Butte mine. The long-term plan that is currently in development updates the plan that was prepared in 2015 and that was the subject of extensive discussion in the 2017 TAM in docket UE 307. The new, updated long-term plan is expected to be available later this year.

Q. Sierra Club also argues that PacifiCorp has not explained how it evaluates key components of CSAs, including the term, price, minimum take levels, and damages.[17] How do you respond?

A. The evaluation of a bilateral CSA is necessarily specific to the individual plant, mine or mines that can serve the plant, and overall coal market. PacifiCorp's approach toward negotiating its multi-year contracts is informed by its industry expertise, years of experience, and long-term relationships with many counter-parties. Mr. Schwartz provides additional evidence on this issue, opining that PacifiCorp's general approach to its multi-year agreements is reasonable and fully consistent with industry

[17] Sierra Club/100, Vitolo/18.

standards, taking into account the illiquid markets in which most of the company's coal plants are located.

Q. Sierra Club contends that the Naughton plant's operations and maintenance costs likely exceed its net energy market revenues during the 2015 and 2016 period. Has Sierra Club provided any evidence to support its position?

A. No, Sierra Club does not provide any analysis, work papers, or other documents to support this position. Naughton is part of the robust IRP process that analyzes PacifiCorp's system portfolio and selects the least-cost, least-risk portfolio. The 2017 IRP does not identify Naughton for closure in the near future, and instead includes it as a resource in the preferred portfolio.

Q. Sierra Club also contends that PacifiCorp's medium and long-term fuel contracts appear to lock the utility into non-economic behavior that results in ratepayer losses. Has Sierra Club provided any evidence to support its position?

A. No. This claim is premised only on Sierra Club's allegation that in 2015-2016, PacifiCorp dispatched the Naughton plant in a non-economic manner. As discussed above, Sierra Club's analysis contains errors that when corrected, demonstrate that the plant was dispatched in the best interests of customers.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 323
Exhibit PAC/700
Witness: Seth Schwartz

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Seth Schwartz

July 2017

REPLY TESTIMONY OF SETH SCHWARTZ

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ATTACHED EXHIBITS

Q. Please state your name, business address and present position.

A. My name is Seth Schwartz. My business address is 1901 North Moore Street, Suite 1200, Arlington, Virginia 22209. My position is President, Energy Ventures Analysis, Inc. (EVA).

Q. Please state your relationship with PacifiCorp d/b/a Pacific Power (PacifiCorp).

A. I am an independent expert PacifiCorp has retained to testify on the issues raised in this case concerning prudent practices for contracting for coal supplies.

QUALIFICATIONS

Q. Briefly describe your professional experience.

A. I am the President of EVA and have been a principal since its founding in 1981. EVA performs market analysis and management consulting for the U.S. energy markets. We cover markets for coal, natural gas, oil and electric power. Our clients are participants in the energy market, including producers, consumers, transporters, investors and regulators. In addition to my corporate responsibilities, I manage our coal consulting practice, including market studies, publications and management consulting. Our market studies include analyses of coal supply, demand, and prices. Our consulting projects include management audits of fuel procurement practices by electric power companies, both regulated and unregulated. Our management audits have included projects for regulatory agencies, interveners, and company management. I have testified as an expert witness on coal markets and coal procurement practices in front of numerous state public utility commissions as well as the Federal Energy Regulatory Commission (FERC). My current resume is attached as Exhibit PAC/701.

Q. Have you previously testified regarding the coal mining operations and coal procurement practices of PacifiCorp?

A. Yes. In 1991, following the merger of Utah Power & Light and PacifiCorp, I directed a study of the coal supply operations and fuel procurement practices of PacifiCorp on behalf of the seven state public service commissions and FERC, as well as a subsequent update in 1995. These studies were comprehensive reviews of the management of the mining operations and coal supply plan for all of PacifiCorp's coal-fired generation facilities. In 2011, I also testified on behalf of the Utah Office of Consumer Services in Docket No. 10-035-124 regarding PacifiCorp's fuel supply management and coal supply operations. More recently, I was a witness for PacifiCorp in state regulatory proceedings in Oregon and elsewhere addressing the closure of the Deer Creek mine.

Q. Do you have previous experience in reviewing the prudence of utility fuel procurement practices and coal supplies?

A. Yes. I have audited and provided testimony regarding the prudence of the fuel supply practices and coal contracting decisions in a number of cases over the course of my career. This experience includes numerous expert reports and testimony on behalf of the Public Utility Commission of Ohio regarding the practices of utilities regulated in that state, including Dayton Power & Light, Cincinnati Gas & Electric, Ohio Power, Columbus Southern Power, Cleveland Electric, Ohio Edison and Monongahela Power. I testified on behalf of utility commissions, intervenors, and regulated utilities regarding the prudence of fuel procurement in the states of Florida, Georgia, Louisiana, Pennsylvania and Texas. I have also worked for utilities preparing internal management audits on behalf of the companies and developed fuel supply plans.

Q. Do you have previous experience in coal procurement operations for coal-fired power plants?

A. Yes. I have been an agent on behalf of the owners of two large merchant coal-fired power plants, responsible for coal procurement activities, including planning and contracting for coal and rail transportation services. I have also acted as an adviser to the coal procurement operations of numerous electric utilities as an outside consultant.

Q. Do you have previous experience in analyzing coal markets and coal contracts and testifying on these issues?

A. Yes. As a regular part of EVA's practice, I analyze coal markets, including coal supply, demand, prices, and contracting activities. We perform this work for coal consumers, producers, transporters, investors, and regulators. I have testified in many cases on coal markets and coal contracting issues, in federal court, state court, arbitration, and regulatory hearings.

PURPOSE AND SUMMARY

Q. What is the purpose of your testimony?

A. Public Utility Commission of Oregon Staff (Staff) and intervenors have filed testimony questioning the need for long-term contracts for coal supply to PacifiCorp's plants, the role of minimum take provisions in coal supply contracts, and the reasonableness of the use of these provisions by PacifiCorp. Staff and Sierra Club have proposed adjustments challenging aspects of PacifiCorp's coal supply forecast for 2018.

The purpose of my testimony is to: (1) describe the structure of coal markets in the United States in general and, specifically, for PacifiCorp's power plants; (2) describe the role of multi-year contracts in supplying reliable and economic fuel to coal-generation facilities; and (3) explain the function of take-or-pay and liquidated damages provisions in coal supply contracts.

Q. Please summarize your conclusions.

A. PacifiCorp's coal-fired power plants were all originally located adjacent to coal mines, either captive operations or with dedicated long-term supply contracts. Except for the Dave Johnston plant, the coal supply options continue to be extremely limited today, with few producers who can supply the plants. As a result, PacifiCorp must rely on multi-year coal supply contracts in order to have reliable and economic coal supplies to operate the plants. Short-term or spot coal purchases are not available or not economic because of the costs associated with mining coal in illiquid markets. Where the supplier has few customers for the coal (as is the case for most of PacifiCorp's coal suppliers), customers must commit to substantial minimum purchase levels (known as "minimum take" or "take-or-pay" provisions) in order to support the economic operations of the coal supplier. These terms are incorporated in multi-year coal supply contracts, and keep the pricing low. It is unrealistic to suggest that PacifiCorp could have large volume swing capability under its multi-year coal contracts yet not pay a higher coal price to obtain this option. It is also unrealistic to suggest in these illiquid coal markets that PacifiCorp could simply contract for lower volume commitments and still expect to have coal available to operate its plants if it wanted to increase plant operations. I believe that PacifiCorp has been prudent in its decisions to contract for coal supplies with third parties under long-term contracts with significant minimum take obligations.

COAL MARKETS IN THE UNITED STATES AND THE ROLE OF LONG-TERM COAL SUPPLY CONTRACTS

Q. Please provide an overview of the structure of coal markets in the United States.

A. In the United States, coal is found in a number of separate geographic and geological regions. Geographically, coal is produced in varying quantities in 25 different states. Geologically, coal is found in many different coalbeds (or seams),[1] created by different depositional environments. Coalbeds located in the same geographic area generally are known as coal basins. Coal quality, coal production costs, and access to customers vary widely among different coal basins. Coal from different coal basins is generally not fungible and customers are not easily and quickly able to substitute coal from one basin for another. As a result, each coal basin tends to operate as a separate market, loosely overlapping with other coal basins as customers can switch coals over a multi-year time period.

Q. How does coal transportation affect the structure of the coal markets?

A. Coal is a bulk commodity where the transportation cost can be a large share of the delivered coal price. The large transportation cost contributes to the separation of coal basins into different markets, as it can be very expensive for customers to switch

[1] The 25 largest producing coalbeds in 2015 accounted for 80% of total national production. U.S. Energy Information Administration, "Annual Coal Report 2015", November 2016, Table 5.

from one coal basin to another. This factor contributes to the separation of coal markets among the different coal basins.

Q. How does coal quality affect the structure of the coal markets?

A. Coal quality can vary widely in heat content, impurities (such as ash, sulfur and moisture), and in combustion characteristics (such as ash fusion temperature and grindability). While coal quality tends to be similar in a coalbed across a coal basin, quality can be very different among different coal basins. As a result, it can be difficult for customers to switch supplies from one coal basin to another, without time and expense to modify facilities to use coal with different quality. This factor contributes to the separation of coal markets among the different coal basins.

Q. How does the structure of coal markets affect the ability of customers to purchase coal?

A. Some coal basins are fairly large markets with multiple suppliers and mining operations. In these markets, coal supply can be fairly liquid which allows customers to purchase coal from multiple suppliers under shorter-term purchases while maintaining reliable supplies. Other coal basins have few producers, in some cases only one mining operation. These markets are highly illiquid and customers must purchase coal under long-term contracts in order to have any reliability of supply.

Q. How does coal transportation affect the ability of customers to purchase coal on the "spot" market?

A. Most coal is delivered in large batches, primarily in trains or barges, which require advance contracting for timely and economic coal deliveries. As a result, there is no "spot" market for coal as conventionally defined, which is a purchase for immediate delivery. In the coal market, a spot purchase is normally considered to be a one-time purchase of coal for delivery in the following month or delivery for up to one year in the future.

Q. How does the structure of the coal markets differ from natural gas and power markets?

A. Both natural gas and power are fungible commodities—the quality is the same for all sources and supply can be substituted among different sources. These products are commingled during delivery and the product is not identified to any particular source (gas well or power plant). Further, these commodities are delivered continuously through pipelines or power lines. The combination of these factors allows for a liquid market which can be traded financially, separate from physical delivery. These features allow for hedging future market prices with financial products and for the purchase of the physical product under short-term contracts and spot purchases. In contrast, coal markets have little or no financial hedging capability and all purchases are under contracts for physical delivery.

Q. What is the typical strategy for coal purchasing employed by electric utilities?

A. Coal procurement strategies vary based upon the characteristics of the coal markets which are the most economic supply to the power plant. In the more liquid coal markets (with many competing coal producers), electric utilities typically purchase most of their coal under contracts with a term of one to three years duration. In these markets, utilities typically use a portfolio of coal contracts to commit to a minimum level of purchases starting at 70 percent-95 percent of expected burn in the first year, declining over time. Spot purchases made during the calendar year typically fill in for variations in coal burn above the minimum burn expectations. When burn falls below expected levels due to unusual factors (such as the unusually mild winter in early 2016 which resulted in very low natural gas prices), utilities can be over-contracted for the current year.

Q. How are utility coal purchasing strategies different in markets with less liquidity?

A. In coal markets where there are only a few, or even just one, producers, utilities cannot rely on short-term contracts or spot purchases to provide reliable and economic coal supplies. Both the consumer and the producer require longer-term contracts to support the investment of hundreds of millions of dollars in power plants or coal mines. In an illiquid market, because there are few coal options, a utility requires a longer-term contract both to induce the supplier to invest in the mining operation and to protect against paying prices far in excess of what would be charged in a competitive market. In turn, the coal supplier in an illiquid market requires a longer-term contract to have an assured market for the coal at a price which is above production costs.

Q. Why do coal supply contracts have "minimum take" provisions?

A. Without a commitment by the customer to purchase a minimum amount of coal, the coal supplier does not have an assured market for the output of the mine; the contract is merely an option for the customer to purchase coal if desired while paying no cost for this option. No coal producer could afford to agree to such a contract as it would require a large investment of capital in reserves, development, and equipment to be available to supply coal with no assurance that any coal would be purchased. Further, coal suppliers (and, similarly, coal transporters) require a commitment to purchase at a regular rate ("ratable take") to employ and maintain a workforce able to meet the customer's requirements. As a result, while some contracts may provide some flexibility for the customer to vary purchase requirements, all coal supply contracts have a minimum volume commitment to purchase coal.

Q. What is the purpose of a liquidated damages provision in a coal supply contract?

A. A liquidated damages provision is a clause which quantifies the damages which a customer pays for the failure to purchase the minimum volume of coal under a coal supply contract. Liquidated damages are an alternative to a take-or-pay provision which requires the customer to purchase the coal or pay for it anyway. Liquidated damages define in advance the amount of the damages, which is a fraction of the purchase price, and typically much less than the damages that the supplier might incur due to the failure to take deliveries. As a result, a liquidated damages provision is a clause that is favorable for the customer, as it quantifies the damages for the failure to purchase coal and provides the customer with an option to purchase less coal at a defined cost if that is the most economic course of action.

Q. How does the ability of the customer to vary contract purchases affect the contract price?

A. The ability to nominate a range of annual coal purchases under a longer-term contract has great value to a customer and great cost to a supplier. If a customer bargains for the right to reduce coal purchases far below the maximum coal supply obligation of the supplier, the customer gains the benefit to adjust purchase levels to a wide range of coal needs. This passes on the risk of variations in coal demand (such as happened when natural gas prices fall to very low levels as they did in 2016) onto the supplier. The requirement to maintain the capacity to provide the maximum volume of coal that the customer can purchase under the contract, while allowing the customer to significantly reduce coal purchases, has a large cost to the supplier. The supplier must maintain the capacity (including the equipment and the workforce) to produce the maximum amount of coal, while the customer may order only the minimum amount. That event would increase the supplier's production cost significantly (especially in illiquid markets where the ability to sell the coal to other customers is limited or non-existent). As a result, the supplier would insist on a much higher contract price to compensate for the risk of the customer reducing purchases in any year.

Q. How do utilities determine the fuel cost for economic dispatch when they have coal supply and transportation contracts with liquidated damages and projected burn falls below the minimum take obligations?

A. Utilities do not include the fixed cost of liquidated damages in determining the variable cost for the dispatch of their power plants. Customers benefit from least-cost dispatch as utilities only include the variable cost of fuel in the decision whether to operate a power plant (just as utilities would not include the fixed cost of a pipeline contract for transportation of natural gas). If the power plant dispatches at the variable cost (subtracting the liquidated damages from the full contract coal price) but would not have dispatched at the full cost, the most economic decision is to dispatch the power plant even though the fuel cost charged to the ratepayer is greater than the fuel cost used for dispatch purposes. If a power plant still does not dispatch economically after subtracting the cost of liquidated damages, then the least-cost decision is to reduce plant operations and pay the liquidated damages.

Q. How does the ability to resell coal affect the least-cost decision?

A. In relatively liquid coal markets, a customer may be able to resell coal at a price below the contract price but above the variable cost after subtracting the cost of liquidated damages. In this case, the power plant should be dispatched at the market price for coal available for resale. However, in illiquid coal markets there is seldom a situation in which coal can be resold at a savings to customers because of the lack of secondary buyers in the area, transportation costs to an available market, or coal quality issues between markets.

PACIFICORP'S COAL-FIRED POWER PLANTS AND COAL SUPPLIES

Q. Please provide some background describing the development of PacifiCorp's coal-fired power plants.

A. Before the 1970's, there was little development of the coal fields in the western United States. As a result, most of PacifiCorp's coal-fired power plants were developed in remote locations where there was no liquid coal market available to supply these plants. These plants were "mine-mouth" plants, intentionally located adjacent to the coal mine supplying the plants. In most cases the mine was developed at the same time as the power plant, either as "captive" operations owned by PacifiCorp or its predecessors, or under long-term contracts with independent coal suppliers. These mine-mouth plants further allowed PacifiCorp the benefit of avoiding expensive coal transportation costs to trucking companies and railroads.

Q. How have the coal supply options for PacifiCorp's plants changed over time?

A. Transportation options and costs have opened up some options, but few of PacifiCorp's coal-fired power plants have access to a liquid coal market. As a result, these plants are supplied by captive operations or under longer-term coal supply contracts that support development of coal mining operations. Over a long period of time, the economics of PacifiCorp's coal suppliers have changed at some of these plants. Some of the original mining operations had costs increase due to depletion of coal reserves, making outside supplies a more economic option. In some cases, the development of the Powder River Basin (PRB) as a large commercial coal basin has provided an option for lower-cost supply where the coal quality can be substituted (usually with additional associated capital investments), and transportation is viable and economic.

Q. In your observation, is PacifiCorp's general approach to negotiating multi-year coal supply agreements with third-parties reasonable and consistent with industry standards?

A. Yes. For the Dave Johnston plant, which can be supplied by multiple suppliers in the PRB, PacifiCorp employs a portfolio strategy with contracts of one to three years duration. PacifiCorp's other plants operate in illiquid markets with few supply options and PacifiCorp uses contracts with longer duration to ensure an adequate supply at reasonable prices.

Q. Please provide a summary of the coal supply options for PacifiCorp's Naughton power plant.

A. The Naughton plant is located adjacent to the Kemmerer coal mine and has been exclusively supplied by Kemmerer since the plant was constructed. There are no current coal supply options as the plant takes delivery by conveyor from the Kemmerer mine and is located remote from any other mining operations. The current Kemmerer coal supply contract is a multi-year-term contract that expires in December 2021. The contract has a base price for a minimum of [redacted] tons per year with coal deliveries over that amount at a much lower price. With the retirement of Naughton unit 3 expected near the end of 2018, PacifiCorp has exercised its contractual right to reduce the minimum purchases to [redacted] tons per year under the Environmental Response provision.

Q. Has PacifiCorp acted prudently in negotiating and implementing its coal supply contract for Naughton?

A. Yes. Because PacifiCorp did not have other economic alternatives for coal supply to Naughton, it was prudent to negotiate a multi-year contract with the adjacent Kemmerer mine. PacifiCorp could not rely upon spot market purchases to supply Naughton, as there is no spot market. The Kemmerer mine sells all of its output to the Naughton plant and several local soda ash producers, all of which are under multi-year contracts extending to 2026.[2] In 2016, the Naughton plant purchased 2.6 million tons from Kemmerer and the other industrial customers purchased 1.5 million tons. PacifiCorp could not have obtained a multi-year coal supply contract without a large minimum take obligation as Kemmerer would have been forced to reduce operations and investment without a customer commitment to purchase the coal. The other

[2] The owner of Kemmerer, Westmoreland Resource Partners, states that "approximately 98.2% of our coal tons were sold under long-term supply contracts." Westmoreland Resource Partners LP, SEC Form 10-K for the year ended December 31, 2016 at 7.

industrial customers have also entered into multi-year contracts because of their lack of coal supply options.

Q. The testimony sponsored by the Sierra Club assumed that the cost of coal to Naughton under a contract for [redacted] tons would have been less than the cost of coal under the Company's actual contract with Kemmerer. Is that a reasonable assumption?

A. No. There is no reason to assume that the cost of coal from Kemmerer would have been the same or less than actually paid by PacifiCorp had the company contracted for lower volumes of coal. I requested information from PacifiCorp regarding the Company's actual costs of coal from the Kemmerer mine. The workpapers provided by PacifiCorp show PacifiCorp's 2016 actual costs of coal from Kemmerer for the base volume of [redacted] tons was [redacted] per ton. Kemmerer's sales to its other industrial customers are also under multi-year contracts at a similar price, reported by the Energy Information Administration to be $41.40 per ton for purchases of 1.4 million tons in 2016.[3] Thus, there is no reason to believe that PacifiCorp could have purchased coal at a lower price than the Tier 1 contract price. Had PacifiCorp insisted on lower minimum volumes for the Tier 1 purchases, as speculated by Dr. Vitolo,[4] the price would likely have been significantly higher if the contract required Kemmerer to maintain the capability to supply the higher volumes but allow PacifiCorp to reduce purchases to much lower levels.

Q. Please provide a summary of the coal supply options for the Jim Bridger plant.

A. The Jim Bridger plant was originally developed with a captive coal supply from the

[3] Energy Information Administration, "Quarterly Coal Report October – December 2016", Tables 26 and 27.
[4] Sierra Club/100, Vitolo/17.

adjacent Jim Bridger surface mine (delivered by conveyor) for all of the plant requirements. Over time, the cost of coal from the surface mine increased due to depletion and PacifiCorp developed the Bridger underground mine and purchased outside coal from the nearby Black Butte coal mine. PacifiCorp installed a limited ability to deliver coal by rail to deliver the Black Butte coal and has considered the purchase of coal by rail from the PRB. There is a substantial investment in the plant and the unloading facilities, with a long lead time required for the plant to use significant quantities of PRB coal.

Q. What is PacifiCorp's strategy for supplying coal to the Jim Bridger plant?

A. It is my understanding that PacifiCorp is currently assessing its long-term fuel supply strategy through development of a long-term fuel plan. To allow PacifiCorp time to complete this assessment and implement its strategy, the company plans to renew its coal supply contract with Black Butte, which expires at the end of 2017 (with some tonnage deferred into 2018) for another three to four years. PacifiCorp has assessed the minimum quantities that it needs to commit to Black Butte to be approximately [redacted] tons per year to support the minimum level of economic operations at the mine.

Q. Based on your understanding of Jim Bridger fuel supply needs, is the Company's decision to execute a three-year contract with the Black Butte mine reasonable?

A. Yes. The Black Butte mine is the only coal supply option immediately available in the quantities and quality required to supplement the Bridger mine coal supply to the Jim Bridger plant. This mine has proven to be a reliable and economic fuel supply source for the plant for many years. Its relative close proximity to the Jim Bridger plant, along with its consistent coal quality, has made the Black Butte mine an important fuel supply source for the plant. A three or four-year contract will provide PacifiCorp with the time needed to develop other coal supply options.

Q. Is it reasonable for PacifiCorp to include a contract minimum in any coal supply agreement with the Black Butte mine?

A. Yes. In 2016, the Black Butte mine produced 2.16 million tons of coal, 100 percent of which was purchased by the owners of the Jim Bridger plant. Due to changes in the coal market, Black Butte has lost all of its other customers and the Jim Bridger plant is its sole remaining market. Before 2016, Black Butte had produced between 2.7 and 4.0 million tons per year. Because of the high fixed costs for equipment and personnel to maintain a mining operation, it is reasonable to expect that Black Butte would require a minimum commitment on the order of [redacted] tons per year to maintain an economic operation. Any lower commitment may change the economics of operation for Black Butte.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 323
Exhibit PAC/701
Witness: Seth Schwartz

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Seth Schwartz

Resume of Seth Schwartz

July 2017

RESUME OF SETH SCHWARTZ

EDUCATIONAL BACKGROUND

B.S.E. Geological Engineering, Princeton University, 1977

PROFESSIONAL EXPERIENCE

Current Position

Seth Schwartz is the President and co-founder of Energy Ventures Analysis (EVA). Mr. Schwartz directs EVA's coal and power practice and manages the COALCAST Report Service. The types of projects in which he is involved are described below:

Fuel Procurement

Assists utilities, industries and independent power producers in developing fuel procurement strategies, analyzing coal and gas markets, and in negotiating long-term fuel contracts.

Fuel Procurement Audits

Audits utility fuel procurement practices, system dispatch, and off-system sales on behalf of all three sides of the regulatory triangle, i.e., public utility commissions, rate case intervenors, and utility management.

Coal Analyses

Directs EVA analyses of coal supply and demand, including studies of utility, industrial, export, and metallurgical markets and evaluations of coal production, productivity and mining costs.

Natural Gas Analyses

Evaluates natural gas markets, especially in the utility and industrial sectors, and analyzes gas supply and transportation by pipeline companies.

Expert Testimony

Testifies in fuel contract disputes and rate cases, including arbitration, litigation and regulatory proceedings, regarding prevailing market prices, industry practice in the use of contract terms and conditions, market conditions surrounding the initial contracts, and damages resulting from contract breach.

Acquisitions and Divestitures

Assists companies in acquisitions and sales of reserves and producing properties, both in consulting and brokering activities. Prepares independent assessments of property values for financing institutions.

Prior Experience

Before founding Energy Ventures Analysis, Mr. Schwartz was a Project Manager at Energy and Environmental Analysis, Inc. Mr. Schwartz directed several sizable quick-response support contracts for the Department of Energy (DOE) and the Environmental Protection Agency (EPA). These included environmental and financial analyses for DOE's Coal Loan Guarantee Program, analyses of air pollution control costs for electric utilities for EPA's Office of Environmental Engineering and Technology, Energy Processes Division, and technical and economic analysis of coal production and consumptions for DOE's Advanced Environmental Control Technology Program.

Publications

Crerar, D.A., Susak, N.J., Borcsik, M., and Schwartz, S., "Solubility of the Buffer Assemblage Pyrite + Pyrrhotite + Magnetite in NaCl Solutions from 200^{o} to 350^{o}", Geochimica et Cosmochimica Acta (42)1427-1437, 1978.