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August 25, 2017

VIA ELECTRONIC FILING

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
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Re: UE 323– In the Matter PACIFICORP, dba PACIFIC POWER, 2018 Transition Adjustment Mechanism

Attention Filing Center:

Attached for filing in the above-captioned docket is an electronic copy of PacifiCorp's Response to Calpine Energy Solutions, LLC's Motion to Strike or in the Alternative to Accept Additional Rebuttal Testimony. The CONFIDENTIAL copies will be sent via overnight delivery.

Please contact this office with any questions.

Very truly yours,

Adam Lowney

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 323

In the Matter of: PACIFICORP d/b/a PACIFIC POWER 2018 Transition Adjustment Mechanism	**PACIFICORP'S RESPONSE TO CALPINE ENERGY SOLUTIONS, LLC'S MOTION TO STRIKE OR IN THE ALTERNATIVE TO ACCEPT ADDITIONAL REBUTTAL TESTIMONY**

In accordance with OAR 860-001-420(4), PacifiCorp d/b/a Pacific Power submits this response to Calpine Energy Solutions, LLC's (Calpine Solutions) Motion to Strike or in the Alternative to Accept Additional Rebuttal Testimony (Motion), which was filed on August 24, 2017. PacifiCorp agrees to withdraw the portion of Mr. Michael G. Wilding's surrebuttal testimony that is the subject of Calpine Solutions' Motion.[1] PacifiCorp's withdrawal of this testimony does not waive PacifiCorp's right to present arguments in this case based on the evidence that remains in the record. This withdrawal makes Calpine Solutions' alternative request for additional testimony moot, as acknowledged by Calpine Solutions in its Motion.[2]

PacifiCorp's agreement to withdraw a portion of its surrebuttal testimony is intended to narrow the disputed issues in this case and prevent additional litigation over the proper scope of the record in this case. Withdrawing the testimony ensures that the hearing set on August 31, 2017, can proceed as scheduled. Calpine's additional testimony is extensive. If the Commission allowed the testimony, PacifiCorp would need several weeks to serve

[1] The testimony that will be withdrawn is PAC/800, Wilding/5, lines 8-14 and PAC/800, Wilding/54 line 11 to 58, line 13.
[2] Motion at 3 ("absent PacifiCorp's withdrawal of the subject testimony (which would moot the alternative request for additional rebuttal testimony), this matter will require Commission resolution.").

discovery, prepare supplemental surrebuttal testimony, file supplemental cross-examination exhibits, and prepare potential cross examination. PacifiCorp's agreement to withdraw the testimony is designed to avoid this scenario and streamline the presentation of this case.

Accompanying this response is revised surrebuttal testimony of Michael G. Wilding (PAC/800) that excludes the testimony that PacifiCorp has agreed to withdraw.

Respectfully submitted this 25th day of August, 2017.

Katherine A. McDowell
Adam Lowney
McDowell Rackner & Gibson PC

Matthew McVee
Chief Regulatory Counsel
PacifiCorp d/b/a/ Pacific Power

Attorneys for PacifiCorp

Docket No. UE 323
Exhibit PAC/800
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Revised Surrebuttal Testimony of Michael G. Wilding

August 2017

SURREBUTTAL TESTIMONY OF MICHAEL G. WILDING

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ATTACHED EXHIBIT

Exhibit PAC/801 – List of Proposed Adustments

Q. Are you the same Michael G. Wilding who previously submitted direct and reply 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 surrebuttal testimony?

A. My surrebuttal testimony responds to various net power cost-related issues and adjustments raised in the rebuttal 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 surrebuttal testimony supporting the 2018 Transition Adjustment Mechanism (TAM).

A. There are two other witnesses providing surrebuttal testimony in support of PacifiCorp's 2018 TAM filing: Mr. Dana M. Ralston and Ms. Kelcey A. Brown.

Q. Has PacifiCorp changed its net power cost (NPC) recommendation in its surrebuttal testimony?

A. Yes. As discussed below, to narrow the issues in dispute, PacifiCorp has accepted a modified version of CUB's and Staff's proposed contract delay rate (CDR) methodology for calculating costs associated with new Qualifying Facilities (QF). Specifically, the company proposes to weight the CDR by contract size (a proposal

Staff supports), and limit the days-in-delay to those within the rate period, or from January 1, if the QF is projected to be in service before the rate period. This adjustment reduces NPC by approximately $204,000.[1]

In all other respects, the reply update filed July 11, 2017, reflects the company's most current forecast of 2018 NPC and sets a reasonable and realistic NPC baseline for 2018. Consistent with the TAM Guidelines, the company will provide a final update in November 2017.

Q. Please summarize the current status of the 2018 TAM filing.

A. PacifiCorp's 2018 TAM proposes a rate increase of $7.7 million, or 0.6 percent overall, which is $10.7 million less than the company's initial filing. The issues outstanding in this case are now relatively narrow for two reasons. First, in its reply testimony and now in surrebuttal, PacifiCorp has incorporated several modeling changes and adjustments proposed by the parties, which have helped moderate the proposed 2018 TAM increase. Second, of the issues that remain contested, many have been litigated and previously rejected by the Public Utility Commission of Oregon (Commission), and the parties have not shown that reconsideration is warranted. Exhibit PAC/801 summarizes the adjustments proposed in this case, including the value of the adjustments still pending.

Q. Please outline your surrebuttal testimony on the company's day-ahead and real-time (DA/RT) adjustment.

A. The Commission approved the company's DA/RT adjustment in 2015 and reapproved it in 2016. In an attempt to minimize continuing litigation over this

[1] Unless otherwise noted, all NPC values are provided on an Oregon-allocated basis.

adjustment in this case, PacifiCorp lengthened the normalization period to five years (which reduced the adjustment), accepted CUB's proposal to add a "collar" to exclude power cost adjustment mechanism (PCAM) recovery years from the historical average, and accepted ICNU's correction to the DA/RT calculation.

Rejecting these efforts at compromise, in rebuttal Staff increases its DA/RT disallowance from $12.8 million to $16.7 million (total-company), while ICNU increases its disallowance from $24.7 million to $26.2 million (total-company). My surrebuttal testimony shows that Staff and ICNU unfairly cherry-pick historical data to justify their DA/RT disallowances, and that Staff's challenge to the volume component of the DA/RT adjustment—for the third year in a row—is no more compelling this year than in previous years.

Q. Please summarize your surrebuttal testimony on Staff's and ICNU's proposal that the company validate the DA/RT adjustment by conducting an NPC backcast.

A. The Commission has never required a backcast to validate NPC adjustment, and there is no reason to deviate from that precedent here. A backcast will create more modeling problems than it will solve, as illustrated by the fact that Staff and ICNU already disagree on how the company should conduct it. While PacifiCorp is supportive of developing methods to validate and improve the accuracy of its NPC forecast, this is most effectively done by comparing forecast and actual data through the PCAM or otherwise. The company is open to a workshop process to address this further.

Q. What is your surrebuttal testimony in response to Staff's coal shutdown adjustment?

A. Staff's adjustment of $3.1 million (total-company) is premised on the incorrect claim that PacifiCorp has shut down coal plants for economic reasons for many years. My surrebuttal testimony shows that economic shutdowns like those modeled by Staff occurred in 2016 and 2017 only, based on non-normal market conditions. Under the forward price curve used to model NPC in this case, the company does not forecast a recurrence of those conditions in 2018. Staff's adjustment also fails to take into account the operational and reliability considerations that preclude economic shutdown of coal units under normal conditions.

On a related issue, Sierra Club has proposed that the company add variable operations and maintenance (O&M) costs in its coal dispatch modeling, and Staff supports this proposal. The company is willing to accept this proposal for the 2019 TAM if these costs are also added into the TAM and PCAM. Because of the potential complexity of this issue, the company suggests addressing it in a technical workshop.

Q. Please summarize the company's position on the QF adjustments proposed by Staff and CUB.

A. In my reply testimony, PacifiCorp agreed to CUB's alternative proposal to track new QF costs in a dollar-for-dollar deferral, as long as the tracker includes all QF costs. In rebuttal, CUB and Staff support application of a three-year CDR, with Staff agreeing that the CDR should be weighted for contract size. As noted above, to narrow the issues, the company accepts a modified version of the CUB/Staff CDR proposal.

Q. Please outline your surrebuttal to Calpine's direct access adjustments.

A. The company's proposed renewable energy certificate (REC) credit constructively responds to Calpine's position on the transition adjustment, while avoiding more complex issues around cost-sharing and REC ownership and transfer. My surrebuttal testimony supports Staff's rebuttal position to use the company's proposed REC credit in the 2018 TAM to allow the Commission to investigate other approaches to this issue for the future.

Q. Please summarize the company's surrebuttal position on inter-regional energy imbalance market (EIM) benefits, as set forth in the testimony of Ms. Brown.

A. In reply testimony, the company responded to Staff's concerns that inter-regional EIM benefits were understated because they did not capture the significant growth in EIM benefits since its inception. The company changed its modeling approach, and increased inter-regional EIM benefits to [redacted] on a total-company basis, an increase of [redacted] over initial filing and within [redacted] of Staff's [redacted] forecast (as corrected). This represents a growth rate of 45 percent, as compared to Staff's proposed growth rate of 51 percent, and is well-supported by the evidence.

In rebuttal, Staff responded to the company's revised inter-regional EIM calculation by increasing its EIM benefits adjustment by approximately [redacted] to [redacted] (total-company). Ms. Brown's surrebuttal testimony demonstrates that Staff's revised EIM benefits forecast double-counts growth from new entrants in 2018, and projects unreasonably high EIM benefits.

Q. Please summarize the company's response to the coal adjustments raised by Staff and Sierra Club, as set forth in the testimony of Mr. Ralston.

A. Staff proposes to adjust the coal price at the Cholla plant by disallowing the use of any coal inventories to fuel the plant and imputing lower liquidated damages of [redacted], total-company. Mr. Ralston's surrebuttal demonstrates that the company is prudent in relying on coal inventories to supply a portion of the Cholla plant's fuel supplies in 2018, and there is no basis for disallowance of liquidated damages. The company also objects to Staff's proposal that PacifiCorp develop a report on its coal contracting practices, but supports holding a technical workshop on the issue.

In its rebuttal testimony, Sierra Club withdrew its adjustment of $2.4 million (total-company) to fuel costs for the Naughton plant. Mr. Ralston's surrebuttal demonstrates that there is no basis for Sierra Club's continuing proposal to restrict the company's coal contracting, a proposal that Staff also opposes based on the risk it presents to customers.

SURREBUTTAL TESTIMONY

Day-Ahead and Real-Time System Balancing Transactions

Response to Staff

Q. Did Staff's recommendations on the DA/RT adjustment change in its rebuttal testimony?

A. Yes, in three ways. First, Staff recommends an entirely new framework for evaluating the DA/RT adjustment, which, as I discuss below, the Commission has never applied to NPC adjustments.[2]

[2] Staff/500, Kaufman/17.

Second, Staff recommends a modification to the methodology used to identify outliers in the historical data set used to calculate the DA/RT adjustment.[3] Staff's primary recommendation is to modify CUB's proposed collar mechanism, to which PacifiCorp agreed in its reply testimony to narrow the issues in dispute. Staff now proposes to greatly expand the scope of CUB's collar so that the DA/RT adjustment will exclude any year where the NPC forecast varies by more than $30 million from actual NPC. In the alternative, Staff recommends that 2013, 2014, and 2015 be excluded from the historical data set as outliers. As I discuss below, Staff's new recommendations have no support in the record and are internally inconsistent with one another, thereby producing contradictory results.

Third, Staff recommends that the Commission eliminate the volume component of the DA/RT adjustment, another adjustment unfairly raised for the first time in rebuttal testimony.[4] As discussed below, Staff's recommendation to eliminate the volume component rehashes arguments already rejected by the Commission. Staff's attempt to justify this recommendation actually verifies both the accuracy and the need for the DA/RT adjustment.

Q. Turning to Staff's first recommendation regarding the framework for evaluating the DA/RT adjustment, Staff claims that PacifiCorp "relies entirely on a comparison of the NPC variance with and without the [DA/RT] adjustment[.]"[5] Is this true?

A. No. PacifiCorp has not argued that its historical under-recovery of NPC is the only,

[3] *Id*.
[4] Staff/500, Kaufman/18.
[5] Staff/500, Kaufman/15.

or even the primary, basis for the DA/RT adjustment—a fact Staff acknowledged last year, but misrepresents this year.[6] As the company explained at length in dockets UE 296 and UE 307 and in its testimony in this case—the DA/RT adjustment is designed to increase the accuracy of NPC by capturing real costs that the company incurs to serve customers that are not otherwise reflected in the NPC forecast produced by the company's Generation and Regulation Initiative Decision Tools model (GRID).

The adjustment creates a more accurate forward price curve by capturing the fact that PacifiCorp typically sells when prices are low and buys when prices are high. This refined forward price curve is then used as an input to the GRID model. The DA/RT adjustment also reflects the additional system balancing transactions that are required in real-time operations but not modeled in GRID due to the model's perfect optimization. PacifiCorp produced expert testimony establishing these market and modeling dynamics, which was a part of the record the Commission relied upon in originally adopting the DA/RT adjustment. It has also addressed market and modeling dynamics in hundreds of pages of testimony, exhibits and analysis in the 2016 and 2017 TAMs, and in the pre-filing workshops in this case.

Q. Did the Commission approve the DA/RT adjustment because of PacifiCorp's historical under-recovery of NPC?

A. No. In neither of its orders approving the DA/RT adjustment did the Commission base its approval on the fact that PacifiCorp had historically under-recovered NPC. In Order No. 15-394, the Commission found that short-term purchase prices

[6] *In the Matter of PacifiCorp d/b/a Pacific Power's 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Staff/400, Kaufman/34 ("Q. Does PacifiCorp directly state that historic under-forecasting of NPC is due to GRID's difficulty in modeling market transactions? A. No. . .").

systematically exceed short-term sales prices and that the DA/RT adjustment "account[s] for these expected price differences [and] will result in a more accurate estimate of net power costs."[7] The Commission also found that GRID understated system balancing volumes because it "assume[s] the volumes of purchases and sales matched exact needs."[8]

In Order No. 16-482, the Commission upheld its decision in Order No. 15-394 that the DA/RT adjustment "reasonably addresses a deficiency of the GRID model and is likely to more accurately capture PacifiCorp's net variable power costs."[9]

Q. Does Staff's testimony address the Commission's rationale for approving the DA/RT adjustment?

A. No. Staff's testimony neither addresses the framework that the Commission used to evaluate the DA/RT adjustment nor acknowledges the Commission's specific findings supporting its decision to approve the adjustment in the last two TAMs.

Q. Does Staff dispute the Commission's finding that short-term purchase prices systematically exceed short-term sales prices?

A. No. Staff agrees that "short-term power purchase prices systematically exceed short-term power sales prices."[10] Moreover, Staff agrees that the forward price curve used in GRID should reflect greater variability and that the variability should correspond to changes in demand.[11] Importantly, the DA/RT adjustment does just this. The adjustment creates more variability in the forward price curve by capturing the price

[7] *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).
[8] *Id.*
[9] Docket No. UE 307, Order No. 16-482 at 13 (Dec. 20, 2016).
[10] Docket No. UE 307, Staff's Response Brief at 26 (quoting PacifiCorp's Opening Brief at 45).
[11] Docket No. UE 307, Staff/200, Kaufman/7-9.

differential between purchases and sales, and reflects the fact that PacifiCorp typically purchases when its demand is higher, thereby correlating the price curve to PacifiCorp's demand.

Q. Has Staff presented evidence contradicting the Commission's orders finding that GRID understates DA/RT transactional volumes?

A. No. Staff has not presented evidence demonstrating that the volume of DA/RT transactions modeled in GRID is comparable to the actual historical volumes.

Q. Staff claims that there is no way to know if the NPC forecast is more accurate because of the DA/RT adjustment unless PacifiCorp performs a backcast analysis to validate the accuracy of the GRID model.[12] Is this a fair criticism of the DA/RT adjustment?

A. No. Staff argues that because PacifiCorp has not proven that the historical under-recovery is due to system balancing transactions, there is no evidence that the DA/RT adjustment will produce a more accurate NPC forecast going forward.[13] Staff's argument, however, misstates the basis for the Commission's approval of the DA/RT adjustment, which, as described above, was not that the DA/RT adjustment would remedy PacifiCorp's historical under-recovery of NPC. Instead, the Commission found that the DA/RT adjustment increases NPC accuracy by modeling costs that have historically been excluded from PacifiCorp's NPC forecast.

Q. Has Staff proposed a new framework for evaluating the DA/RT adjustment?

A. Yes. Staff argues that the Commission should reapprove the DA/RT adjustment only after PacifiCorp provides analysis validating the accuracy of GRID in a way that will

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[12] Staff/500, Kaufman/19-22.
[13] *Id*.

allow parties to review the DA/RT adjustment in isolation from other variables impacting the accuracy of the NPC forecast.[14]

Q. Has the Commission ever applied Staff's evaluation framework to an NPC modeling adjustment?

A. No, Staff's proposal is completely unprecedented. Over the years, the Commission has approved many NPC modeling refinements, including modeling changes similar to the DA/RT adjustment that rely on historical data to forecast future costs. The Commission has never required PacifiCorp, or any party, to justify the change only after performing the type of backcast analysis Staff recommends here. For example:

- In the 2008 TAM, the Commission adopted Staff's proposed adjustment to reflect the margin earned by PacifiCorp from its arbitrage and trading activity.[15] Staff argued that this margin was not accounted for in GRID and calculated its credit using three years of historical data.[16]

- In the 2012 TAM, the Commission approved PacifiCorp's proposal to improve the accuracy of the NPC forecast by using hourly scalars derived from historical data. The Commission found that "a key purpose of the GRID model is to determine the economic dispatch of Pacific Power's resources on an hourly basis," and the "use of hourly scalars is intended to develop results consistent with historical price data."[17] Staff supported the company's proposed scalars, and ICNU did not object to the calculation of the scalars using historical data.

- In the 2013 TAM, the Commission affirmed the use of market caps to model market liquidity.[18] The market caps approved by the Commission included a modification recommended by Staff and ICNU. Rather than use the historical average transaction volumes, the modified caps used the highest historical monthly transaction level at each market hub modeled in GRID.

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[14] Staff/500, Kaufman/22.
[15] *In the Matter of PacifiCorp d/b/a Pacific Power 2008 Transition Adjustment Mechanism,* Docket No. UE 191, Order No. 07-446 at 10-11 (Oct. 17, 2007).
[16] *Id.* at 9.
[17] *In the Matter of PacifiCorp d/b/a Pacific Power 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435 at 18-20 (Nov. 4, 2011).
[18] *In the Matter of PacifiCorp d/b/a Pacific Power 2013 Transition Adjustment Mechanism,* Docket No. UE 245, Order No. 12-409 at 7-8 (Oct. 29, 2012).

The Commission did not condition its approval of any of the adjustments discussed above on performance of a backcast, nor did the Commission impose this condition on approval of the DA/RT adjustment in the 2016 and 2017 TAMs.

Moreover, the Commission has never required Idaho Power Company (Idaho Power) to conduct a backcast to justify use of a conceptually identical forward price curve that differentiates prices based on whether the utility is buying or selling in the market. Just this year, Staff reviewed Idaho Power's methodology and did not question the use of two prices or claim that the use of a more refined forward price curve is unreasonable without a backcast analysis to determine the basis for the historical discrepancies between forecast and actual NPC.[19]

Staff has also supported a conceptually similar system balancing transactions adjustment to Portland General Electric Company's (PGE) NPC forecasting to account for system balancing transactions made at the California Oregon Border (COB) market that are not otherwise included in PGE's modeling.[20] Staff's support for the system balancing adjustment was not conditioned on any requirement that PGE first validate its NPC model so that parties could examine the system balancing transactions adjustment in isolation. Instead, Staff argued that its methodology for forecasting system balancing transactions at COB produced more accurate results and

[19] *In the Matter of Idaho Power Company, 2017 Annual Power Cost Update,* Docket No. UE 314, Staff/100, Gibbens/12-16.
[20] The COB adjustment, and its similarities to the DA/RT adjustment, were described extensively in Docket No. UE 296. *See* Docket No. UE 296, PAC/500, Dickman/36-37; Docket No. UE 296, PacifiCorp's Opening Brief at 12-14.

should be approved.[21]

Q. In addition to a wholly new framework for evaluating the DA/RT adjustment, has Staff also proposed new modifications to the adjustment?

A. Yes. For the first time in its rebuttal testimony, Staff recommends a new adjustment that would affect the historical data used to calculate the DA/RT adjustment. Staff recommends that CUB's proposed collar mechanism be modified to remove any year with a symmetrical NPC variance of $30 million from the historical data set used to calculate the adjustment.[22] In the alternative, Staff recommends that 2013, 2014, and 2015 be excluded.[23] In its reply testimony, PacifiCorp accepted CUB's collar mechanism, which excludes any year where a PCAM adjustment is triggered from the historical data set, to reduce litigation over the DA/RT in this case. Staff's rebuttal now seeks to expand the scope of litigation based on the company's concession, discouraging such compromises in the future.

Q. Why does Staff propose excluding historical data from the data used to calculate the DA/RT adjustment?

A. Staff is concerned that the use of historical data will not produce a normalized result.

Q. Is Staff's concern over normalization new?

A. No. What is new is that in prior years, parties were concerned that PacifiCorp was relying on *too little* historical data. To respond, PacifiCorp extended the historical

[21] *In the Matter of Portland General Electric Company, 2017 Annual Power Cost Update Tariff*, Docket No. UE 308, Staff/300, Kaufman/6 ("Staff recommends that the Commission adopt Staff's method to calculate the net benefits obtained from PGE's access to the COB market. Staff's methodology is simple and can be easily integrated into PGE's modeling and produces more accurate results than the methodology proposed by PGE. Staff plans to undertake more complete analysis of the Company's valuation method in next year's AUT in order to obtain more precise valuation of the trading margin.").
[22] Staff/500, Kaufman/17.
[23] Staff/500, Kaufman/17.

average to four years in the 2017 TAM. Then, as a result of discussions in the pre-filing workshops in this case, the company agreed to further extend the average to five years. While Staff was initially supportive of these modifications, it now claims that PacifiCorp is relying on *too much* historical data.

Q. Does PacifiCorp's use of a longer, five-year average in this case reduce the DA/RT adjustment as compared to previous cases?

A. Yes. The five-year average produces lower DA/RT costs than either a three- or four-year average.

Q. Has the Commission previously rejected arguments that the DA/RT adjustment produces a non-normalized result?

A. Yes. The Commission has consistently rejected claims that the use of historical data to calculate the DA/RT adjustment produces a non-normalized result. In the 2016 TAM, the Commission expressly found that the use of three years of historical data was sufficient to produce a normalized adjustment.[24] After PacifiCorp proposed a four-year average in the 2017 TAM, the Commission found that "four years of data is sufficient to generate a normalized result and that PacifiCorp's adjustment is based on an analysis of a reasonable set of transactions."[25]

Q. How do you respond to Staff's primary recommendation for a collar mechanism that excludes any year where the NPC variance is more than $30 million?[26]

A. This proposal is flawed because Staff has not shown that a $30 million NPC variance has any correlation to whether DA/RT transactions are normal or abnormal. Indeed,

[24] Order No. 15-394 at 4.
[25] Order No. 16-482 at 13.
[26] Staff/500, Kaufman/28.

Staff argues that there is no relationship between PacifiCorp's historical DA/RT costs and the historical variance between forecast and actual NPC.[27]

Q. Would Staff's modified collar operate to exclude the years it claims are outliers in its alternative proposal?

A. No, which demonstrates the arbitrary nature of both proposals. Staff's collar would exclude 2011, 2013, and 2014 from the historical data set.[28] But Staff's alternative proposal would exclude 2013, 2014, and 2015 as outliers.[29] Thus, Staff's adjustments are internally inconsistent.

Q. Why is Staff's alternative recommendation to exclude 2013, 2014, and 2015 from the DA/RT calculation flawed?

A. Most fundamentally, Staff has no basis to claim that these years are outliers—a fact that Staff concedes when admitting that there is insufficient historical data to even identify outliers.

Q. How does Staff justify its claim that 2013, 2014, and 2015 are outliers?

A. Staff simply looks at the DA/RT transaction levels from these three years and concludes that because the DA/RT costs in 2013 to 2015 are higher than the costs in the other three years of available data (2011, 2012, and 2016), 2013 to 2015 are abnormal, while the other three years of data with lower DA/RT costs are normal.

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[27] *See* Staff/500, Kaufman/14(PacifiCorp's historical under-recovery can be attributed to model input error such as coal costs); Docket No. UE 307, Staff's Response Brief at 26 (PacifiCorp "provides no evidence that there is a relationship between historic market power prices and PacifiCorp's past net power cost forecast error."); Docket No. UE 307, Staff/400, Kaufman/34 (providing "evidence" that there is not a "direct relationship between the historic above average market cost of transactions and the purported underestimate of power costs in GRID").

[28] *See* PAC/400, Wilding/43 (showing NPC variances greater than $30 million in 2011, 2013, and 2014).

[29] Staff/500, Kaufman/17.

Q. Are there inconsistencies in Staff's analysis purporting to identify outlier years?

A. Yes. Staff presents two different analyses that appear to identify the same DA/RT costs, but each analysis uses different historical DA/RT costs and identifies different "outlier years" (which, in turn, are also different than the outlier years identified by Staff's collar).

First, on page 25 of its testimony, Staff graphically represents the "DART Costs" based on the analysis performed by ICNU. This graph shows that 2012, 2013, and 2014 have greater DA/RT costs than 2011, 2015, and 2016. Based on this graph, Staff argues that 2012, 2013, and 2014 represent an "abnormal" spike in costs because they are "clustered together."[30] But Staff admits that there is limited historical data related to DA/RT costs, and therefore there is insufficient data "to draw conclusions about whether these three years are normal or abnormal."[31] Thus, Staff concludes only that 2012, 2013, and 2014 "*could* be abnormal."[32]

Second, on page 27, Staff presents another graph that also displays "DART Costs" (in addition to "Actual Realtime Transactions"). The graph on page 27 shows that 2013, 2014, and 2015 have greater costs than 2011, 2012, and 2016. Apparently based on this graph, Staff recommends that 2013, 2014, and 2015 are outliers that should be excluded from the historical data set. Staff never reconciles these two graphs or explains why one is correct and the other is not, why one is more reliable than the other, or why the purported outliers in one are different from the purported

[30] Staff/500, Kaufman/24. Staff also populated its graph with additional made-up numbers to further support its claim that 2012, 2013, and 2014 are outliers.
[31] Staff/500, Kaufman/24.
[32] Staff/500, Kaufman/24 (emphasis added).

outliers in the other. Moreover, if the analysis presented on page 25 is insufficient to identify outliers, then the analysis on page 27 is likewise deficient.

Q. Are there any other problems with Staff's analysis?

A. Yes. The fact that three out of five years are clustered together does not suggest that those years are outliers. On the contrary, the clustering of those three years suggests that the remaining two years are the outliers. It appears Staff simply decides that the years with the highest system balancing costs are outliers even though they are more representative of the historical data set than the years Staff claims are normal. Staff concedes that there is insufficient historical data to even identify outliers, which eliminates any basis for its own adjustment.

Q. Staff also notes that DA/RT costs are highly volatile, based on the same argument presented by ICNU.[33] Does that volatility support Staff's proposal to use only two years of historical data to normalize DA/RT costs?

A. No. On the contrary, when an input is volatile, a longer historical period is typically necessary to produce a normalized result.

Q. Following ICNU's response testimony, Staff also claims that PacifiCorp's participation in the EIM has reduced its need for system balancing costs.[34] Is this true?

A. No. As I described in my reply testimony, PacifiCorp's participation in the EIM has not affected the need for the DA/RT adjustment.[35] There is no basis for Staff to claim that system balancing costs are expected to be lower going forward.

[33] Staff/500, Kaufman/23-24.
[34] Staff/500, Kaufman/25-26.
[35] PAC/400, Wilding/28-29.

In addition, to the extent that the participation in the EIM does impact the system balancing costs, that impact—whether positive or negative—will flow through the adjustment due to the use of a historical average.

Q. Staff also claims that PacifiCorp's real-time transactions were substantially lower in 2016 than in previous years, and infers that this result was caused by participation in the EIM.[36] How do you respond?

A. The lower DA/RT costs in 2016 are primarily due to the fact that natural gas prices unexpectedly plummeted. These reduced prices meant that PacifiCorp could rely more on its natural gas generating resources to economically balance its system and did not have to rely on market purchases to the same extent as in the past. While the participation in the EIM may have impacted 2016 as well, the primary driver was natural gas prices. Again, if the level of DA/RT costs incurred in 2016 proves to be more representative of future years, then those lower DA/RT costs will roll into the DA/RT adjustment through the historical average and decrease the adjustment in future years.

Staff's description of 2016 transactions is also flawed. First, Staff misclassifies the transactions, as evidenced by the fact that its analysis purporting to exclude known hedging transactions differs from ICNU's analysis purporting to show the same thing.[37] Second, Staff claims that "[i]n 2016, PacifiCorp recorded zero real time purchases."[38] This is not true—in 2016 PacifiCorp had over 3,000 real time purchases.

[36] Staff/500, Kaufman/26-27.
[37] Staff/500, Kaufman/32; ICNU/200, Mullins/3.
[38] Staff/500, Kaufman/26-27.

Q. Do you expect 2018 to have natural gas prices that would allow PacifiCorp to rely on its own generating resources more than the market to balance its system, like it did in 2016?

A. No. The historically low natural gas prices in 2016 are not expected to recur in 2018.

Q. Although Staff does not support ICNU's proposal to include greater-than-seven-day (*i.e.*, hedging) transactions in the DA/RT adjustment, Staff argues that ICNU's proposal is not a true-up of the forward price curve to the actual monthly price, as PacifiCorp claimed.[39] How do you respond?

A. First, Staff's testimony does not dispute that ICNU's proposal would include hedging transactions in the DA/RT adjustment, which ICNU previously opposed. Second, ICNU's proposal includes the difference between the actual prices of the hedging transactions and the actual monthly average market price. This essentially trues-up all hedging transactions to the actual monthly price. Staff is therefore incorrect that ICNU only trues-up the known, short-term firm transactions already included in GRID.

Q. Turning to Staff's recommendations to eliminate the volume component of the DA/RT adjustment, Staff reiterates its concern that the volume component of the DA/RT adjustment does not account for the residual value associated with monthly transactions.[40] Has Staff provided any additional basis for this claim?

A. No. Staff rehashes its previously rejected arguments against the DA/RT volume component, and relies on the same hypothetical as in its opening testimony, which presumes the following:

[39] Staff/500, Kaufman/31.
[40] Staff/500, Kaufman/30.

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.[41]

As I explained in my reply testimony,[42] without the DA/RT adjustment, GRID would model these transactions as if PacifiCorp purchased 5,000 MWh at the average monthly price of $20 per MWh, for a total cost of $100,000. In reality, however, the cost of the 5,000 MWh was $150,000. Staff claims that the price-adder component of the DA/RT adjustment captures part two because, with the DA/RT adjustment, GRID would make a real-time purchase of 5,000 MWh for $30 per MWh, with a total cost of $150,000. Staff appears to agree with PacifiCorp's analysis and concedes that the price component of the DA/RT adjustment is necessary for the forecast to reflect the actual costs incurred. But Staff reasons that the volume component is unnecessary because the price component fully captures the DA/RT costs.[43]

Q. Is Staff correct that the price component would fully capture the costs incurred in part two of its hypothetical, rendering the volume component of the DA/RT adjustment unnecessary?

A. No. Staff is correct that in this hypothetical the price adjustment fully captures the DA/RT cost, but that means that the volume component would reflect a 5,000 MW

[41] Staff/200, Kaufman/18.
[42] PAC/400, Wilding/19-21.
[43] Staff/500, Kaufman/33.

sale, and the price of that sale would be $0.00. As PacifiCorp has described, the volume component accounts for the DA/RT costs that are not otherwise captured by the GRID model. In Staff's hypothetical, the GRID model captures the full DA/RT costs associated with the hypothetical transactions (through the price adjustment) and therefore the volume component would reflect zero additional costs. In Staff's hypothetical, it is not that the volume component is unnecessary, it is that the volume component is zero. In other words, the volume component only appears unnecessary because in Staff's hypothetical, the GRID-adjustment price perfectly captures the DA/RT costs, leaving no need for the additional correction provided by the volume component of the adjustment.

Q. Can you provide an example demonstrating how the price and volume components work together to fully capture DA/RT costs?

A. Yes. Assume that in addition to the hypothetical described above, in the same month PacifiCorp also engaged in the following transactions:

4. PacifiCorp buys a monthly product with 10,000 MWh valued at $20 per MWh for a total of $200,000.
5. PacifiCorp sells 5,000 MWh in daily products priced at $5 per MWh, for a total revenue of $25,000 (*i.e.*, PacifiCorp sells this 5,000 MWh block at a different time that the sale in part two).
6. PacifiCorp keeps the remaining 5,000 MWh in daily products which are valued at $30 per MWh, for a total value of $150,000.

As previously discussed, parts one, two, and three result in PacifiCorp incurring $150,000 for 5,000 MWh. Parts four, five, and six result in PacifiCorp incurring

$175,000 for 5,000 MWh, or a total cost of $325,000 for 10,000 MWh. Without the DA/RT adjustment, GRID would purchase the 10,000 MWh at the monthly price of $20 per MWh, for a total cost of $200,000—$125,000 less than the costs actually incurred. With the DA/RT price adjustment, GRID would purchase 10,000 MWh at $30 per MWh, for a total cost of $300,000—$25,000 less than the costs actually incurred. In this example, the volume component of the DA/RT adjustment would account for the 10,000 MWh that is sold in parts two and five, and price those transactions at $2.50 per MWh, for a volume component adjustment of $25,000. Thus, in total, GRID with the DA/RT adjustment would account for the full $325,000 for 10,000 MWh. If the volume component is eliminated, as Staff recommends, GRID would model $25,000 less costs than were actually incurred.

Q. Has Staff calculated the NPC impact of its proposal to "[r]educe the NPC forecast to account for the residual value of monthly and daily transactions?"[44]

A. No. Staff has made this proposal in both its opening and rebuttal testimony; however, Staff has not provided a calculation of this adjustment or even a description of how the calculation would be performed. Thus, Staff cannot claim that this adjustment produces a more accurate NPC forecast because there is no explanation of how this adjustment actually works.

[44] Staff/500, Kaufman/34.

Q. Staff also argues that additional balancing transactions are not real incremental costs, that a monthly transaction should be priced based on the average monthly price, and that the only way a monthly transaction would impose an incremental cost is if the average expected monthly price is too high or too low.[45] Is this correct?

A. No. Staff's example above demonstrates the flaw in its reasoning. Parts two and five above produce a "real incremental cost" that is not accounted for in GRID without the DA/RT adjustment. Staff appears to agree on this point, which undermines its testimony that there are no real incremental costs.[46]

Q. Staff also claims that there is no way to judge whether to use the DA/RT adjustment or an arbitrary adder, the so-called Staff's More Accurate Real Time (SMART) adjustment, which simply adds an arbitrarily determined value to the TAM's price per megawatt-hour.[47] How do you respond to Staff's SMART adjustment?

A. Staff's criticism of the DA/RT adjustment as simply a fixed-price adder is flawed. First, the refined forward price curve created by the DA/RT adjustment is a GRID input that impacts the dispatch of PacifiCorp's resources. Therefore, it is not simply a fixed-price adder. Staff claims that these non-fixed aspects are "minor,"[48] but in both the 2016 and 2017 TAMs, the non-fixed pricing component of the DA/RT adjustment was greater than the volume component, and in this case, the non-fixed pricing

[45] Staff/500, Kaufman/30.
[46] Staff/500, Kaufman/33 (agreeing the price component of the DA/RT adjustment is necessary).
[47] Staff/500, Kaufman/20-21.
[48] Staff/500, Kaufman/21 n. 37.

component is approximately 40 percent of the total DA/RT adjustment.[49]

Second, while Staff is not convinced that the DA/RT adjustment reflects real costs that are incremental to GRID, the Commission has made this exact finding twice. Staff concedes later in its testimony that the DA/RT adjustment is necessary to capture costs that are not otherwise modeled in GRID—contradicting its testimony that the DA/RT adjustment does not reflect real costs incremental to GRID.[50] Therefore, the DA/RT adjustment is not just an arbitrary fixed-price adder—it is calculated using a robust data set of historical transactions and, as the Commission has found, reflects real costs that are not included in GRID.

Q. In support of its claim that the DA/RT adjustment is arbitrary, Staff points to its testimony in docket UE 307 that the adjustment remains substantial even when GRID forecasts no market transactions.[51] Is this persuasive?

A. No. As PacifiCorp explained in docket UE 307, the purpose of the DA/RT adjustment is to capture system balancing transactions that are not modeled in GRID and reflect transaction volumes that are consistent with historical levels. It is unsurprising that when GRID models fewer transactions, the DA/RT adjustment models more.

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[49] Docket No. UE 296, PAC/500, Dickman/14-15 (pricing component was $4.3 million, volume component was $3.7 million); Docket No. UE 307, PAC/400, Dickman/21-22 (pricing component was $5.4 million, volume component was $3.6 million).
[50] Staff/500, Kaufman/33.
[51] Staff/500, Kaufman/15 n. 31.

Response to ICNU

Q. In support of its position that the DA/RT adjustment should include hedges (*i.e.*, transactions in excess of 7 days), ICNU claims that if hedging transactions provide customer benefits, they should be included.[52] Please respond.

A. Including hedging transactions is contrary to the fundamental purpose of the DA/RT adjustment, which the Commission approved to correct a systematic under-forecast of the system balancing costs associated with transacting in the day-ahead and real-time markets. Simply put, the costs and benefits realized from hedging transactions are not DA/RT costs and there is no evidence that hedging costs are systematically under- or over-forecasted by GRID. Indeed, in docket UE 296, ICNU explicitly argued that hedging costs should not be included in the DA/RT adjustment because there is no systematic costs or bias associated with hedging.[53]

When transacting in the future market, PacifiCorp uses a daily forward price curve as a point of reference for future monthly prices. The forward price curve represents PacifiCorp's best estimate of futures prices based on history, trader experience, and third-party information. If PacifiCorp transacts at a fixed price in the forward market, then it is very likely the actual monthly market price will be either above or below the fixed price. The difference in the fixed price obtained in the forward market and the actual monthly price (or the price at which the market liquidated) is not a systematic deficiency in GRID.

[52] ICNU/200, Mullins/9.
[53] Docket No. UE 296, ICNU/100, Mullins/7-8.

Q. Does ICNU's own analysis in this case demonstrate that hedging transactions are not systematically under-forecast in GRID?

A. Yes. ICNU's Confidential Table 1R, shows that the day-ahead and real-time market transactions (*i.e.*, the less-than-seven-day transactions) impose an additional cost in every year when compared to the actual monthly market price. Without the DA/RT adjustment these costs are not captured in GRID because GRID will transact at the monthly market price, thereby systematically under-forecasting DA/RT costs.

In contrast, ICNU's analysis of hedging transactions (*i.e.*, the greater-than-seven-day transactions), shows that those transactions impose costs in some years and benefits in others, indicating that there is no systematic bias one way or the other. The lack of a systematic bias is also demonstrated by the fact that when ICNU includes the hedging transactions in the DA/RT adjustment, they have a relatively modest impact when the DA/RT adjustment is appropriately normalized using five years of historical data.

Q. In addition to including longer-term transactions, ICNU also recommends that PacifiCorp calculate the DA/RT adjustment using only two years of historical data.[54] Is it reasonable to calculate the adjustment using only two years of historical data?

A. No. Two years of historical data will not produce a normalized forecast, particularly when ICNU also includes hedging transactions in the adjustment. As noted above, over the long-term, hedging transactions do not tend to systematically impose a cost or provide a benefit. But using a shorter time horizon, as ICNU proposes, can distort

[54] ICNU/200, Mullins/11.

the normalized impact of hedging transactions. This fact is shown clearly by ICNU's adjustment.

Using only two years of data and including hedging transactions produces a DA/RT adjustment of only $1.4 million. If ICNU instead used a five-year historical period, its method would produce a DA/RT adjustment that is almost $25 million higher ($26.3 million) and within roughly five percent of the DA/RT adjustment (without hedging) because the costs and benefits of the hedging transactions nearly net to zero over the five-year period. In other words, ICNU's recommendation ignores the relatively small impact of hedging transactions when they are normalized using a robust historical data set. The real impact of ICNU's adjustment is its reliance on only two years of historical data.

In addition, ICNU's argument for using only two years of historical data is unpersuasive. ICNU proposes using only two years of historical data to calculate its adjustment based on little more than the fact that 2015 was the first full year of EIM. Coincidently, 2015 and 2016 show the largest benefit realized from the hedging transactions, but ICNU fails to draw any correlation between the two.

Q. Does ICNU's adjustment produce an abnormally low DA/RT adjustment based on ICNU's own data?

A. Yes. Confidential Figure 1 below shows the results from ICNU's Confidential Table 1R and demonstrates that its selected adjustment—which includes hedging transactions and relies on only two years of historical data—is substantially lower than the result of the other potential methodologies shown for calculating the DA/RT adjustment.

CONFIDENTIAL FIGURE 1

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Q. ICNU claims that PacifiCorp's DA/RT costs have declined dramatically since the company joined the EIM and that the DA/RT costs will remain materially lower going forward.[55] Is this true?

A. No. ICNU claims that between 2014 and 2015, PacifiCorp's system balancing costs (both DA/RT costs and hedging transactions) decreased by 87.7 percent because of the EIM, which supports excluding all pre-2015 data from the DA/RT adjustment. But ICNU overstates the magnitude of the decline by inappropriately including the hedging transactions—as noted above, the 2015 to 2016 average DA/RT costs decreased by only six percent relative to the 2011 to 2016 average.

ICNU reasons that because 2015 and 2016 hedging transactions resulted in a benefit, this is the new normal. As Staff acknowledged in its testimony, however, the historical data set is too limited to identify outliers or to proclaim that all pre-EIM data is now obsolete. And ICNU's own evidence demonstrates that the 2015 DA/RT costs were 21 percent *higher* than the previous 48-month average.

The purpose of using a historical average is to smooth out year-to-year variations and produce a normalized forecast of DA/RT costs. ICNU's proposal to

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[55] ICNU/200, Mullins/10.

rely on only two years of data is insufficient to create a normalized result, particularly when ICNU's only basis for the limited historical data set is its anecdotal conclusion that the EIM has made all pre-EIM data obsolete. As I noted in my reply testimony, CUB made this exact argument last year, and it was rejected by the Commission.

Q. ICNU further contends that it would be imprudent if PacifiCorp did not change the way that it balances its system since joining the EIM.[56] Did you testify, as ICNU claims, that the EIM has had "zero" impact on the way PacifiCorp balances its system?

A. No. My testimony stated that the EIM has not fundamentally changed how PacifiCorp balances its system; I did not testify that it has had no impact. The purpose of my testimony relating to the EIM was simply to point out that the historical data related to system balancing transactions remains a valid data set for purposes of calculating the DA/RT adjustment even though PacifiCorp now participates in the EIM.

Q. Please explain the relationship in ICNU's proposed adjustment between PacifiCorp's participation in the EIM and hedging transactions.

A. As seen in Confidential Figure 1 above, ICNU's proposed adjustment is significant only if the calculation is based on post-EIM data and includes hedging transactions. DA/RT costs alone do not dramatically decline post-EIM; therefore, two years is not sufficient to normalize the adjustment. Moreover, ICNU provides no evidence that the EIM has fundamentally changed the way PacifiCorp transacts in the forward market or engages in hedging transactions. Neither component of ICNU's adjustment

[56] ICNU/200, Mullins/9.

stands on its own and each component, without the other, results in only a minimal change to the DA/RT adjustment.

Q. ICNU further claims that its recommendation should not be dismissed out of hand simply because the Commission has previously rejected ICNU's other DA/RT recommendations.[57] Is this a fair characterization of PacifiCorp's position?

A. No. ICNU's position here is that the DA/RT adjustment is flawed because it does not account for hedging transactions. In docket UE 296, ICNU made the exact opposite argument, claiming in that case that the DA/RT adjustment was flawed because it included hedging transactions. Thus, it is not that ICNU's recommendation here should be dismissed because ICNU's other DA/RT recommendations have been rejected. It is that ICNU is now taking the opposite position and never acknowledged that fact or justified its reversal. Indeed, even after I flagged this inconsistency in my reply testimony, ICNU's rebuttal testimony still fails to reconcile its previous position in docket UE 296 with its position here.

Q. ICNU claims that the purported benefits of hedging transactions result from hedging components is "irrelevant" because customers should receive the benefits regardless.[58] How does this compare to ICNU's previous positions?

A. In docket UE 296, ICNU's testimony explained that the "system balancing costs in question are actually concerned with hedging contracts" and that if hedging produces "systematic costs, or biases associated with entering into forward hedging transactions, there would be reason to rethink the prudence of the company's entire

[57] ICNU/200, Mullins/4-5.
[58] ICNU/200, Mullins/9.

hedging policy, as well as the equity of passing those hedging costs onto customers."[59] Based on this testimony, in its briefing, ICNU argued that the DA/RT adjustment "assign[s] costs to hedging contracts in the normalized NPC forecast, *costs which are not appropriately borne by customers*."[60] ICNU further argued that if there was a systematic bias in hedging transactions, it would be contrary to "traditional Oregon ratemaking standards presuming no systematic bias[.]"[61] If the costs of hedging should not be borne by customers, as ICNU previously argued, then the benefits should not be assigned to them either.

ICNU also testified in docket UE 296 that the "historical gains and losses on hedging transactions are indicative of changing market conditions between the time that the hedge is entered into and the prompt period."[62] Thus, according to ICNU, the "historical data is reflective of market conditions in the historical period, which will not correspond to the market conditions implicated by the forward prices in the company's power cost forecast."[63] Applying ICNU's same rationale here provides a direct justification for excluding hedging transactions from the DA/RT adjustment and rejecting ICNU's adjustment.

[59] Docket No. UE 296, ICNU/100, Mullins/7-8.
[60] Docket No. UE 296, Confidential ICNU Response Brief at 7 (emphasis added).
[61] Docket No. UE 296, Confidential ICNU Response Brief at 5.
[62] Docket No. UE 296, ICNU/100, Mullins/15-16.
[63] Docket No. UE 296, ICNU/100, Mullins/16; *id.*at 17 (hedging gains and losses "reflect the impact of changing market prices between the period that the transaction was made and the ultimate spot price. These gains and losses, however, have no bearing on the bid-ask spreads between the rate at which the Company can buy and sell in the market.").

Q. ICNU further argues that the DA/RT adjustment is too narrowly focused on only market transactions without considering the other system dynamics that influence the decision to go to market to balance PacifiCorp's system.[64] How do you respond?

A. ICNU has provided no persuasive evidence demonstrating that the Commission was wrong when it rejected the same argument last year. For example, ICNU provided the following example purporting to show the flaws in the DA/RT adjustment:

> [C]onsider a day with low market prices relative to the monthly average. To the extent that the Company made a large volume of sales on that particular day, it would result in additional cost in the DA/RT adjustment. It is not necessarily true, however, that those particular transactions represented an additional cost on the system. In fact, those low-priced sales transactions might have produced a great deal of economic benefits to the system[65]

In this example, ICNU ignores the fundamental purpose of the DA/RT adjustment and the deficiency in GRID the adjustment corrects. ICNU is correct that PacifiCorp could have sales on a day where the price is below the monthly average and that this would result in additional costs in the DA/RT adjustment (because the sales would be priced less than the monthly average price). ICNU is even correct that these sales might have produced an economic benefit to the system. But ICNU ignores the fact that without the DA/RT adjustment, GRID uses the monthly average price. Therefore, GRID would model the sales at the higher average monthly price, resulting in a larger economic benefit than is actually realized. In this example, the DA/RT adjustment limits the benefits modeled in GRID, by adding an additional cost to match what can be realized in actual operations.

[64] ICNU/200, Mullins/6-7.
[65] *Id*.

Accuracy of NPC Forecast

Q. Both Staff and ICNU recommend that the Commission require PacifiCorp to perform a backcast analysis to validate the accuracy of its NPC modeling.[66] Does PacifiCorp object to validating its NPC modeling?

A. No. PacifiCorp supports efforts to validate GRID and welcomes parties' efforts to more closely scrutinize how effectively GRID forecasts NPC. PacifiCorp does not agree, however, that a backcast analysis is the most effective way to validate the model.

As I described in my reply testimony, PacifiCorp believes that backcasting will prove to be a burdensome and contentious process that will produce little meaningful insight into how to improve GRID. Indeed, both Staff and ICNU already disagree on how to conduct the backcast and the time period to cover, demonstrating that the process will not be a straightforward, mechanical exercise of inputting agreed-upon historical data into the model and then analyzing the output. ICNU and Staff also disagree on the fundamental purpose of a backcast—Staff claims it will be used to improve GRID, while ICNU says such a claim is "misleading."[67]

Q. Is a backcast a useful tool for validation of an electric dispatch model?

A. Not according to the U.S. Department of Commerce's National Bureau of Standards.

[66] Staff/500, Kaufman/2; ICNU/200, Mullins/12.
[67] Staff/500, Kaufman/4 (faulting PacifiCorp's comparison of forecast to actual NPC because "it does not provide any method of *improving* the model. . .") (emphasis in original); ICNU/200, Mullins/11 (PacifiCorp's claim that the purpose of backcast is to modify GRID is "somewhat misleading").

In a publication entitled "Validation and Assessment of Issues of Energy Models,"[68] the Department states that "'[b]ackcasting' is no easier than forecasting. In backcasting and forecasting, you need to assume expectations. There is no comprehensive data source for expectations."[69] Thus, "it is clear that backcasting is not a useful approach to model validation."[70]

Q. Staff recommends that before filing the 2019 TAM, PacifiCorp perform a backcast on at least the last five years, and then perform a backcast every year within the PCAM.[71] Is this a reasonable recommendation?

A. No. Given the level of contention that will be involved in performing a backcast analysis for a single year—keeping in mind that Staff and ICNU already disagree on how it should be performed—it is highly unlikely that the company could perform this analysis before filing the 2019 TAM. Moreover, if every PCAM involves a separate process to litigate a backcast, it will create undue burden on the Commission, PacifiCorp, and the parties.

Q. If PacifiCorp supports model validation, what is the company's proposal?

A. PacifiCorp recommends that the parties convene a workshop following the conclusion of this case to discuss a model validation process, which could include a backcast analysis, greater use of actual results through a re-designed PCAM, or some other method. Subsequent workshops can then examine the results of any validation

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[68] The publication is available at the following website: https://books.google.com/books?id=FZzcRXw5FzwC&pg=PA142&lpg=PA142&dq=model+validation+with+actual+historical+data&source=bl&ots=b5H_qypBNC&sig=4Kn1bUuz5isJph1zIuNgggpmsKY&hl=en&sa=X&ved=0ahUKEwjjyd3_kbzVAhVCLmMKHeGSC68Q6AEIWTAH#v=onepage&q=model%20validation%20with%20actual%20historical%20data&f=false.

[69] *Id.* at 142.

[70] *Id.*

[71] Staff/500, Kaufman/13.

analysis. PacifiCorp's proposal would largely mirror the workshops that were held following the 2017 TAM, which the parties generally agreed were useful.

Importantly, as discussed above, the parties have provided no compelling basis to limit or eliminate the DA/RT adjustment pending the model validation process proposed here. The Commission has approved many modeling refinements—proposed by PacifiCorp, Staff and intervenors—without requiring a model validation process.

Q. Staff claims that PacifiCorp's position is that the main driver of the differences between forecast and actual NPC is related to DA/RT transactions.[72] Is this true?

A. No. PacifiCorp recognizes that there are many reasons that the forecast and actual NPC will differ, as the company has explained in numerous proceedings before the Commission. For example, differences between forecast and actual market prices, or generation levels, or loads, or weather can all contribute materially to a variance between forecast and actual NPC. As I discuss above, Staff's characterization of the company's position on the relationship between its historical under-recovery of NPC and the DA/RT adjustment is incorrect.

Q. Staff identifies historical input errors, like incorrectly forecasted coal costs, which have contributed to the historical variance between forecast and actual NPC.[73] Would a backcast analysis provide useful information related to input errors?

A. No. As I believe Staff concedes, a backcast analysis will do nothing to improve the

[72] Staff/500, Kaufman/2.
[73] Staff/500, Kaufman/5-6.

accuracy of the forecasted inputs that are used in the GRID model. The fact that backcasting provides no insight into reducing input errors is particularly important here, because in the 2017 TAM, Staff argued that "PacifiCorp's historical forecast error is fundamentally grounded in error forecasting the model inputs, such as fuel costs and hydro generation"—not the model itself.[74] Like Staff in the 2017 TAM, in the 2016 TAM, ICNU argued that the "difference between the level of normalized NPC included in rates and actual NPC is ultimately driven by the accuracy of the forecast inputs into the model—the loads, forward prices, and forecasted changes to the company's portfolio."[75] According to ICNU, GRID does not understate normalized NPC—the "difference between normalized and actual NPC is an indication that the model did not correspond to actual weather and plant conditions that occurred during the test period, *not that the GRID model produced an inaccurate normalized forecast*."[76]

Q. Staff also disputes that comparing forecast NPC to actual NPC provides sufficient validation of the GRID model.[77] How do you respond?

A. PacifiCorp believes that the comparison of forecast to actual NPC is an appropriate starting point in any model validation process. As noted above, however, PacifiCorp is open to workshops on various model validation proposals, including potential modifications to the PCAM.

[74] Docket No. UE 307, Staff's Response Brief at 27.
[75] Docket No. UE 296, ICNU/200, Mullins/8.
[76] Docket No. UE 296, ICNU/200, Mullins/8 (emphasis added).
[77] Staff/500, Kaufman/9.

Q. Why did PacifiCorp point out that 2016 was the most accurate TAM forecast to date?

A. PacifiCorp intended to demonstrate that, based on the one year of data, the TAM is producing a reasonable forecast of NPC. The intent was not to imply that parties could not raise concerns with certain costs or components of the TAM.

Q. Parties brought up the cost associated with the one-time abandonment of the Joy Longwall included in actual NPC.[78] If those costs are adjusted out of the actual NPC, is the 2016 TAM still the most accurate?

A. Yes. Figure 2 below shows the same table from my rebuttal testimony, but with the Joy Longwall costs adjusted out. 2016 remains the most accurate TAM to date.[79]

FIGURE 2

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	342,591,463	(4,464,107)

[78] *See, e.g.*, Staff/500, Kaufman/7.
[79] Staff testifies that the Joy Longwall impacted NPC by $30 million. But the $30 million impact was the impact to the Bridger Coal Company, of which PacifiCorp is only a two-thirds owner. When the $30 million figure is reduced to reflect PacifiCorp's ownership interest, and then allocated to Oregon, the NPC impact is considerably less than $30 million.

Coal Plant Dispatch

Q. Staff claims that PacifiCorp performed economic shutdowns of coal plants in every year from 2013 to 2017.[80] Is this true?

A. No. As I described in my reply testimony, PacifiCorp shut down a limited number of coal units in 2016 and 2017, in response to abnormal market conditions caused by historically low natural gas prices in 2016 and historically high hydro generation in 2017. In 2013 to 2015, PacifiCorp did not shut down coal plants due to economic conditions with the exception of one 13-day economic shutdown in 2015.

Q. Why would Staff claim that PacifiCorp shut down coal plants in 2013 to 2015?

A. Staff does not explain its position, but it appears that Staff is implying that very short extensions of maintenance-related outages (a few hours or days) are the same as a one-or-two month shutdown of a plant for economic reasons. This is untrue.

PacifiCorp periodically extends outages for several hours or days for various operational reasons, including if there is no immediate need to bring the unit back online when the outage is over. For example, of the five shutdowns of this nature in 2013, three lasted for less than 10 hours, one lasted for a little over 24 hours, and one lasted roughly a week. The weeklong shutdown, however, was not for economic purposes—it was necessitated by a transmission outage that prevented the plant's output from reaching load. Similarly, in 2014, there were three shutdowns, none of which lasted more than six hours. In 2015, three of the six shutdowns are less than 24 hours. The other three shutdowns occurred at the Cholla plant; the first was the 13-day economic shutdown, the second was the 66 hours between two forced outages,

[80] Staff/500, Kaufman/35.

and the third was after a forced outage that completed the day before Thanksgiving and, due to low holiday loads, the unit was delayed coming back on until the next week.

Extending an outage for several additional hours is very different from Staff's proposal to model the shutdown of coal plants for long periods of time in 2018. First, the duration of the extended outages in 2013 to 2015 was a matter of hours, or sometimes days. Staff has proposed shutting down coal plants for months. These two scenarios are not comparable.

Second, when PacifiCorp extends an outage for several hours it incurs no additional start-up costs. If, on the other hand, PacifiCorp shuts down a coal plant as Staff recommends, PacifiCorp will incur incremental start-up costs.

Third, extending an outage for several hours does not pose the same operational or reliability risks that result from prolonged economic shutdowns.

Q. Staff claims that PacifiCorp did not dispute that GRID does not model economic shutdowns.[81] Is this true?

A. Yes. GRID does not model economic shutdowns because, as I explained in my reply testimony and above, economic shutdowns are extremely unusual events caused by abnormal market conditions. GRID is designed to produce a normalized forecast of NPC and, in a normal year, PacifiCorp does not economically shut down coal plants.

[81] Staff/500, Kaufman/36.

Q. Staff also claims that the real test of whether it is economic to shut down a coal plant is to compare the coal plant's marginal costs to market prices.[82] Is this a fair test?

A. No. Staff supports this claim by citing to a PacifiCorp data response that described the analysis used when PacifiCorp chose to economically shut down coal plants in 2015 and 2016. According to Staff, the "dominant factor" in that analysis was market prices.[83] This testimony is also misleading—the data response does not state that the "dominant factor" is market prices. In fact, the data response, which Staff attached to its testimony, states:[84]

> PacifiCorp considers both economics and reliability in its determination of displacement of resources. Transmission congestion, voltage support, and other operational issues such as maintaining adequate system inertia all play a critical part in determining if a resource can be displaced.

Q. Staff defends the fact it relied on intuition to identify periods for economic shutdowns, claiming that it is up to PacifiCorp to propose a more mechanical process to model economic shutdowns.[85] How do you respond?

A. PacifiCorp's concern over Staff's intuitive approach to selecting economic shutdowns is based on the fact that Staff looked at economics only and did not consider any other issues, like reliability. Staff does not dispute that it failed to consider reliability, or any other non-economic factors, when modeling economic shutdowns. In addition, as noted above, PacifiCorp has not proposed a modeling change to account for economic shutdowns because they do not occur in a normal year.

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[82] Staff/500, Kaufman/36.
[83] Staff/500, Kaufman/36, n. 58.
[84] Staff/501, Kaufman/3.
[85] Staff/500, Kaufman/38-39.

In any event, Staff's recommendation that the Commission direct PacifiCorp to develop a formal modeling method for economic shutdowns is inconsistent with its argument that the DA/RT adjustment cannot be justified until GRID is validated (even though the Commission has closely examined and approved the DA/RT adjustment twice in the last two years). If the DA/RT modeling refinement is improper until PacifiCorp performs a backcast analysis, then Staff's coal plant modeling refinement is equally improper.

Q. Staff also agrees that if economic shutdowns are modeled, PacifiCorp should update its coal costs to reflect the decreased dispatch.[86] Do you object to this recommendation?

A. No. PacifiCorp agrees that if economic shutdowns are modeled, coal costs must be adjusted. In addition, an economic shutdown of the Cholla plant will also potentially impact Staff's adjustment related to liquidated damages at that plant. Thus, Staff's Cholla coal cost adjustment will also need to be updated if the Commission adopts Staff's recommendation to model economic shutdowns. Each of these updates to coal costs will potentially increase NPC.

Q. Staff claims that its proposal will not adversely impact system reliability because GRID will modify dispatch to maintain sufficient reserves.[87] How do you respond?

A. As I explained in my reply testimony, the units that Staff proposes to shutdown are being used to hold load-following reserves. The company must be able to follow load and respond to changes in variable energy within the hour. Because GRID is an

[86] Staff/500, Kaufman/39.
[87] Staff/500, Kaufman/44.

hourly model, market transactions, like those that displaced the coal units, can be used to follow load. In actual operations, however, PacifiCorp cannot use market transactions to follow load. So, while in GRID market transactions provide the same flexibility benefits as coal units, this is not the case in actual operations.

Q. Staff claims that any impact on EIM benefits from an economic shutdown would be minimal.[88] Is this correct?

A. A coal unit realizes benefits in the EIM from its flexibility. For example, if going into the hour a coal unit is dispatched above its minimum, EIM can dispatch the plant down to its minimum to import lower cost. Staff has provided no analysis or evidence supporting that lost EIM benefits would be minimal.

Furthermore, Staff claims that the company runs its coal plant when uneconomic to try and realize a benefit in EIM.[89] This is not true; in reality, the ability to realize benefits in EIM is an integral part of the economic analysis of a coal plant.

Q. Staff also argues that the fact that natural gas prices were historically low in 2016, and are not expected to be that low in 2018, has no bearing on whether PacifiCorp will economically shutdown coal plants in 2018.[90] How do you respond?

A. Natural gas prices are highly relevant because, as I discussed above, in actual operations, PacifiCorp would not shut down a coal plant and assume that its output would be replaced by market purchases. In 2016, PacifiCorp was able to shut down

[88] Staff/500, Kaufman/41.
[89] Staff/500, Kaufman/26.
[90] Staff/500, Kaufman/42.

coal plants because the output could be economically displaced by natural gas generation, which provides the operational flexibility and benefits that market transactions lack. Similarly, in the spring of 2017, record hydro conditions in the Northwest provided additional length to the company's physical position, which allowed the displacement of coal generation.

Q. Staff claims that modeling economic shutdowns is not a complex process and that PacifiCorp has had sufficient time to make this change in this case.[91] Is this true?

A. No. Modifying the GRID model to allow economic shutdowns of coal units would be a complex task because the decision to economically shut down each coal plant is unique. Staff claims PacifiCorp would prefer a formulaic approach as opposed to Staff intuition.[92] In truth, PacifiCorp does not believe there is a formulaic approach that can adequately capture the unique and often times noneconomic variables that are considered when deciding whether to shut down a coal plant. Additionally, the company is opposed to modeling the economic shutdown of coal plants based on Staff's intuition because it is not as simple as just modifying planned outage schedules or identifying a period when GRID appears to model an economic shutdown, as Staff claims.

Moreover, Staff's claim that this issue was raised in prior TAMs is based on the fact that the issue was raised informally during docket UE 307. To be clear, neither Staff nor any other party has ever recommended that GRID be modified to model total shutdowns of coal plants.

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[91] Staff/500, Kaufman/42-43.
[92] Staff/500, Kaufman/38.

Q. Will modeling economic coal shutdowns increase the accuracy of the TAM?

A. No. Figure 3 shows that, on average, that approximately 61 percent of PacifiCorp's total requirement (retail load plus wholesale sales) is served by its coal fleet. In recent TAMs, however, approximately 59.7 percent of PacifiCorp's total requirement is served by its coal fleet. Excluding 2016, this is only a 1.3 percent difference. Even in 2016, with the economic shutdowns present in actuals, but not in the TAM forecast, there was a five percent difference in the dispatch of coal relative to the total requirement. Additionally, the July update in the 2018 TAM shows 51.5 percent of the total requirement being served by coal. In short, GRID already sufficiently optimizes the coal fleet beyond what can be achieved in actual operations.

FIGURE 3

Coal Generation % of Total Requirement			
Year	Actual (MWh)	TAM (MWh)	Difference
2012	60.10%	59.79%	0.31%
2013	62.38%	60.43%	1.95%
2014	60.47%	59.25%	1.22%
2015	60.98%	59.37%	1.61%
2016	56.32%	51.15%	5.17%

Q. Staff also questions whether its proposed shutdown of the Cholla plant would be impacted by the Arizona Public Service Electric Company (APS) Exchange.[93] Please describe why the APS Exchange impacts Staff's proposed Cholla shutdown.

A. The APS Exchange is a contractual agreement between APS and PacifiCorp that was entered into when PacifiCorp acquired an interest in the Cholla plant in 1990. The exchange gives APS the call option for a certain amount of energy between May 15

[93] Staff/500, Kaufman/43.

and September 15 each year. The amount that can be called is constrained by weekly and monthly load factors defined in the contract, but in any given hour APS can call for up to 480 MW. In actual operations, the Cholla plant serves the majority of the call because of its access to APS' balancing authority area (BAA). If the Cholla plant is not online, PacifiCorp and APS must agree on an alternative delivery point, which will increase PacifiCorp's costs to meet its obligation under the APS Exchange.

Q. Staff also claims that PacifiCorp has historically shut down multiple units at the Jim Bridger plant and therefore its proposed shutdown of multiple Jim Bridger units is an acceptable risk.[94] How do you respond?

A. Staff identified two instances in recent history where more than one Jim Bridger unit was offline at the same time. In 2014, a Jim Bridger unit was on planned outage (*i.e.*, an outage that was scheduled well in advance for large-scale overhaul activities), and then six days later another Jim Bridger unit was taken off for a maintenance outage caused by an unexpected circumstance. PacifiCorp had very little control over the timing of the second outage. In 2016, PacifiCorp cycled one unit offline for economics and then a second unit was brought offline for a maintenance outage. After completing the repairs, the unit was kept offline for less than six days due to low loads. Neither of these examples demonstrate that PacifiCorp has regularly taken more than one unit offline at a time, or indicated that Staff's proposed shutdown is reasonable.

Staff also claims that because the units will not be offline for maintenance purposes, they can be immediately available for restart in the case of an emergency.[95]

[94] Staff/500, Kaufman/44.
[95] Staff/500, Kaufman/44.

As Staff correctly testified in docket UE 307, however, "[c]oal plants take a relatively long time to increase or decrease generation [and] can require over 10 hours to generate at capacity from a cold start."[96]

Additionally, as PacifiCorp explained in response to a Staff data request attached to Staff's testimony,[97] there are many reasons PacifiCorp tries to avoid having more than one Jim Bridger unit off at a time. Jim Bridger provides substantial operational flexibility to the system because it is able to provide regulating reserve to both BAAs and is the primary supply of voltage support for PacifiCorp West BAA.

Q. Staff also compares its proposal to the screening process PacifiCorp uses for natural gas plants.[98] Is this a fair comparison?

A. No. PacifiCorp uses a screening process for its natural gas plants because in normal conditions, those plants regularly do not dispatch in actual operations. Thus, the screening process conforms GRID to actual operations. This is not the case for coal plants, where, as discussed above, PacifiCorp does not regularly shut down its coal units.

Additionally, unlike natural gas plants, coal plants are subject to a supply curve. The coal supply curve directly impacts the coal dispatch tier prices and the pricing tier prices. Coal volumes are determined by GRID based on the economic dispatch of the coal plant between its minimum and maximum outputs. If coal plants were to be subject to a similar screening process as the natural gas plants, then the coal supply curve would have to be taken into account, including minimum take

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[96] Docket No. UE 307, Staff/200, Kaufman/43.
[97] Staff/501, Kaufman/4
[98] Staff/500, Kaufman/44-45.

requirements, which would greatly complicate the process.

Finally, the gas screening process is currently an outside model process that assumes that coal plants will be running at their minimum levels and are ready to pick up any reserve shortage when necessary. If coal screening is implemented, it would need to occur before the gas screening because the coal plants are usually lower in the dispatch stack and therefore the coal plant dispatch will impact gas screenings.

Q. Sierra Club and Staff recommend that PacifiCorp include variable O&M expenses in GRID for purposes of determining coal plant dispatch.[99] Does PacifiCorp agree?

A. Yes, but not in this year's TAM. Sierra Club's recommendation is intended to increase the dispatch price of coal, which will result in lower coal generation. Staff argues that including the variable O&M costs in the dispatch decisions will be more accurate because actual dispatch prices include variable O&M costs. As discussed above, further limiting coal dispatch is unnecessary because GRID already understates coal dispatch.

Despite this fact, PacifiCorp is amenable to including the variable O&M costs in the GRID model, provided that variable O&M costs are treated as truly variable costs and are included in the TAM and PCAM. Because modeling variable O&M costs is a significant modeling change, and because PacifiCorp does not update average fuel costs in the final update, PacifiCorp recommends that the parties address this issue in a technical workshop, so that any modeling change can be implemented in next year's TAM.

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[99] Staff/200, Gibbens/22; Sierra Club/200, Vitolo/2.

Modeling QF Contracts

Q. Has Staff updated its position on modeling new QFs?

A. Yes. Staff now recommends adoption of a CDR based on the last three years of available data, similar to CUB. Staff agrees that the data should be weighted by capacity, however, as originally proposed by PacifiCorp.[100]

Q. Do you accept CUB's and Staff's recommendation for a CDR, with modifications?

A. Yes, PacifiCorp accepts CUB's and Staff's recommendation for a CDR, as long as it is weighted by capacity and the delay is counted based on the number of days in the TAM year, so that a delay that does not affect rates is not considered when setting rates. To address CUB's concern over PacifiCorp's methodology,[101] if the proposed commercial online date (COD) is before the TAM year, then the delay rate will be applied beginning on January 1 of the TAM year. For example, if a QF has a proposed COD of November 15, 2017, and actually comes online on January 15, 2018, the delay would be calculated as 15 days, not 61 days. But the 15-day delay would start at the beginning of the TAM year, so the QF would have a modeled COD of January 15, which corresponds to its actual COD. PacifiCorp's recommendation reduces NPC by $204,000.

Q. Did CUB accept PacifiCorp's proposal to weight the CDR by capacity?

A. No. CUB's adjustment makes no differentiation based on the size of the QF, and results in an NPC reduction of $353,000. Figure 4 shows the CDR based on each parties' proposal:

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[100] Staff/600, Anderson/11.
[101] *See* CUB/200, Jenks/14.

FIGURE 4

QF Delay Rate (Days)

	Company Proposal Weighted and Days in Rates	CUB Proposal Unweighted	Staff Proposal Weighted
CY2017 (UE307)	94	212	101
CY2016 (UE296)	21	92	44
CY2015 (UE287)	69	51	87
QF Average Delayed Days	**61**	**119**	**78**

Q. What is the basis for CUB's argument against capacity weighting the CDR?

A. CUB argues that PacifiCorp's proposal to weight QF delays based on the capacity that is delayed, rather than just the number of QFs, would not produce a more accurate forecast.[102] But QF costs are volumetric – as QF generation increases so do QF costs and vice versa. Therefore, it makes sense to weight the delay rate by QF capacity. If a 10 MW QF is delayed, it will cost customers much less than if an 80 MW QF is delayed. The average delayed days weighted by QF nameplate capacity is about 60 days, using three years of TAM history.

Q. CUB also criticizes PacifiCorp's proposal to calculate delays based only on the delay days in the TAM year.[103] How do you respond?

A. The purpose of calculating the CDR based only on the delay days in the TAM year is that a delay outside the TAM year (either before or after) does not affect the rates paid by customers. For example, in TAM year 2017, if a QF is expected to be online on November 20, 2016, but the actual online date is December 20, 2016, this delay had no impact on the TAM forecast nor did it impact customer rates. Similarly, in

[102] CUB/200, Jenks/13.
[103] CUB/200, Jenks/13.

TAM Year 2017, if a QF is expected to be online on November 20, 2016, but the actual online date is January 20, 2017, the relevant delay for purposes of customer impact is 20 days.

CUB's concern relates to the scenario where a proposed COD is before the TAM year. As noted above, to address this concern, PacifiCorp proposes to calculate the CDR based on delay days in the TAM year, but begin counting the delay at the beginning of the TAM year.

Calculating the CDR using only the delayed days from the TAM year also creates a clean break when calculating the three-year average. This allows for delays that span more than one TAM year to be clearly accounted for in the TAM year in which the costs are included in rates.

Direct Access – REC Obligation

Q. Calpine continues to recommend that PacifiCorp calculate the direct access REC credit using current REC prices.[104] Did Calpine reconcile this recommendation with the Commission's findings in Order No. 16-482?

A. No. Calpine ignores the Commission's findings from the 2017 TAM and makes no attempt to reconcile its position here with the Commission's conclusions in Order No. 16-482. As I described in my reply testimony, the Commission found in Order No. 16-482 that a freed-up REC today would defer PacifiCorp's renewable portfolio standard (RPS) compliance obligation in the future.[105] Therefore, the value of a freed-up REC today is equal to the deferred value of RPS compliance. Consistent

[104] Calpine Solutions/200, Higgins/6-7.
[105] Order No. 16-482 at 22.

with the Commission's findings, PacifiCorp's proposed REC credit is calculated as the value of PacifiCorp's deferred RPS compliance obligation.

Q. Calpine argues that direct access customers are unfairly disadvantaged if they do not receive a REC credit based on current prices.[106] Is this the correct metric for determining the value of the REC credit?

A. No. It is my understanding that Oregon law prohibits unwarranted cost-shifting as a result of direct access customers—*i.e.*, the framework for direct access is intended to leave remaining customers no worse off than they would be without direct access.[107] The statutory framework does not impose the same requirements for customers that choose to participate in direct access. Thus, the focus of the inquiry must be on protecting remaining customers, not ensuring that direct access customers are no worse off for having chosen direct access. As the Commission found last year, a freed-up REC today provides little or no benefits to remaining customers. So, if remaining customers pay current prices for freed-up RECs that provide little or no benefit, remaining customers will be harmed.

Q. Calpine also argues that PacifiCorp could simply transfer the RECs, in lieu of a credit, and that the REC that is selected for transfer could be the same REC that PacifiCorp would have retired if the customer had remained.[108] How do you respond?

A. As I explained in my reply testimony, while seemingly very simple, it is not a straightforward exercise to equitably identify the RECs that PacifiCorp would have

[106] Calpine Solutions/200, Higgins/7.
[107] *See, e.g.*, ORS 757.607(1).
[108] Calpine Solutions/200, Higgins/12.

retired if the customer had remained. While following general principles and guidelines (for instance, shorter-lived RECs are retired first), the company has discretion in determining which RECs to retire for a particular RPS compliance year. Because electric service suppliers (ESS) have essentially paid for a pro rata share of all of PacifiCorp resources, it would be administratively burdensome to identify which RECs should appropriately be allocated to a specific customer.

Q. Calpine also proposes a process to allow PacifiCorp retire RECs on behalf of direct access customers.[109] How do you respond to this proposal?

A. PacifiCorp continues to believe that retirement on behalf of an ESS is unworkable. An ESS has its own independent compliance obligation and should be responsible for demonstrating its RPS compliance to the Commission. At this time, there is no clear path for an ESS to fully indemnify the company from any liability associated with demonstrating compliance on their behalf. Moreover, although Calpine claims that PacifiCorp would not have to demonstrate ESS compliance with its RPS obligations, Calpine's proposal would impose an additional RPS compliance obligation on PacifiCorp to include in its reports the RECs retired on behalf of direct access customers.

[109] Calpine Solutions/200, Higgins/12.

Q. Staff supports PacifiCorp's REC credit for this year's TAM, but recommends that the Commission convene a generic investigation to determine a longer-term solution.[110] Calpine makes a similar proposal, but recommends adopting its REC credit in the interim.[111] How do you respond to these proposals?

A. PacifiCorp agrees with Staff's approach and recommends that this year's TAM include PacifiCorp's proposed REC credit, which should remain in place pending additional investigation. My understanding is that PGE does not include a REC credit in its transition adjustment calculation. Because the resolution of this issue could therefore affect more than just PacifiCorp, a generic proceeding appears to be the appropriate forum in which to address this issue.

Direct Access – Schedule 200 Escalation

Q. Calpine claims that PacifiCorp has implicitly agreed that the Consumer Opt-Out Charge includes incremental generation expenses in years six through 10.[112] Is this a correct characterization of your testimony?

A. No. To be clear, PacifiCorp's position in this case, and in dockets UE 267, 296, and 307, is that there are transition costs for at least 10 years after a customer elects to participate in the five-year direct access program. The Commission made this finding explicitly in Order No. 15-060 and adopted a methodology that calculates transition costs using the same methodology for the entire ten-year period.[113] That methodology does not preclude the inclusion of incremental fixed generation costs in

[110] Staff/600, Anderson/8.
[111] Calpine Solutions/200, Higgins/15.
[112] Calpine Solutions/200, Higgins/18.
[113] *Re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-out,* Docket No. 267, Order No. 15-060 (Feb. 24, 2015).

the calculation of the Consumer Opt-Out Charge in years six through 10, just as incremental fixed generation costs are included in the first five years.

PacifiCorp's evidence demonstrates that its fixed generation costs increase at a rate greater than inflation—meaning that the methodology used to calculate the Consumer Opt-Out Charge actually understates the transition costs in years six through 10.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's **Response to Calpine Energy Solutions, LLC's Motion to Strike or in the Alternative to Accept Additional Rebuttal Testimony** 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 25th day of August 2017.

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