PACIFIC POWER
A DIVISION OF PACIFICORP

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August 11, 2017

VIA ELECTRONIC FILING,
OVERNIGHT DELIVERY,
AND HUDDLE

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

Attn: Filing Center

Re: UE 323 – PacifiCorp Surrebuttal Testimony and Exhibits

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

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

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

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

CERTIFICATE OF SERVICE

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

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Dated this 11th day of August, 2017.

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
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.

With respect to the company's calculation of its Consumer Opt-Out Charge, I demonstrate that Calpine is incorrect to claim that the company's fixed costs decline between years six through 10 when incremental generation is removed. Between 2007 and 2015, for example, PacifiCorp's fixed generation costs increased by 11 percent. This demonstrates the reasonableness of the company's 2.5 percent inflation adjustment in years six through 10—an adjustment the Commission has repeatedly approved.

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]

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

[2] Staff/500, Kaufman/17.
[3] *Id*.
[4] Staff/500, Kaufman/18.

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, 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

[5] Staff/500, Kaufman/15.
[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. . .").

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 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.

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[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).

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 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

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

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 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

[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.

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.

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

[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).
[19] *In the Matter of Idaho Power Company, 2017 Annual Power Cost Update*, Docket No. UE 314, Staff/100, Gibbens/12-16.

(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 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.

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[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.

[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.

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 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

[24] Order No. 15-394 at 4.

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, 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

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

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.

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

[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).

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 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.

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[33] Staff/500, Kaufman/23-24.

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.

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.

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[34] Staff/500, Kaufman/25-26.
[35] PAC/400, Wilding/28-29.
[36] Staff/500, Kaufman/26-27.

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.

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.

[37] Staff/500, Kaufman/32; ICNU/200, Mullins/3.
[38] Staff/500, Kaufman/26-27.
[39] Staff/500, Kaufman/31.

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:

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

[40] Staff/500, Kaufman/30.
[41] Staff/200, Kaufman/18.
[42] PAC/400, Wilding/19-21.

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 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:

[43] Staff/500, Kaufman/33.

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.

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]

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[44] Staff/500, Kaufman/34.
[45] Staff/500, Kaufman/30.
[46] Staff/500, Kaufman/33 (agreeing the price component of the DA/RT adjustment is necessary).

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 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.

[47] Staff/500, Kaufman/20-21.
[48] Staff/500, Kaufman/21 n. 37.
[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.

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.

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]

[51] Staff/500, Kaufman/15 n. 31.
[52] ICNU/200, Mullins/9.
[53] Docket No. UE 296, ICNU/100, Mullins/7-8.

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.

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 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.

[54] ICNU/200, Mullins/11.

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

[55] ICNU/200, Mullins/10.

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 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

[56] ICNU/200, Mullins/9.

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 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

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

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 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

[58] ICNU/200, Mullins/9.
[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.

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.

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

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

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.

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

[66] Staff/500, Kaufman/2; ICNU/200, Mullins/12.

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. 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.

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[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").
[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.

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 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.

[72] Staff/500, Kaufman/2.

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 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]

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

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.

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]

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[77] Staff/500, Kaufman/9.
[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.

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)

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

[80] Staff/500, Kaufman/35.

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, 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

[81] Staff/500, Kaufman/36.

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.

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

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

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.

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.

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[86] Staff/500, Kaufman/39.

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 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.

[87] Staff/500, Kaufman/44.
[88] Staff/500, Kaufman/41.
[89] Staff/500, Kaufman/26.

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 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

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

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.

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 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

[93] Staff/500, Kaufman/43.
[94] Staff/500, Kaufman/44.

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] 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

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

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 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

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

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.

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,

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

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:

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

[102] CUB/200, Jenks/13.

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 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.

[103] CUB/200, Jenks/13.

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 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

[104] Calpine Solutions/200, Higgins/6-7.
[105] Order No. 16-482 at 22.
[106] Calpine Solutions/200, Higgins/7.
[107] *See, e.g.*, ORS 757.607(1).

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 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

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

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.

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

[110] Staff/600, Anderson/8.
[111] Calpine Solutions/200, Higgins/15.
[112] Calpine Solutions/200, Higgins/18.

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 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. Calpine claims that PacifiCorp agrees that if the Consumer Opt-Out Charge does not include incremental generation expense after year five, the charge should decline.[114] Is this true?

A. No. Calpine reaches this conclusion by cherry-picking the data provided by PacifiCorp. For example, Calpine claims that when incremental generation capital additions are removed, PacifiCorp's fixed generation costs declined between 2008 and 2015.[115] But Calpine can only make that claim by using 2008 as the starting point. Calpine's analysis shows that between 2007 and 2015, PacifiCorp's fixed generation costs *increased by 11 percent*, and from 2009 to 2015 the fixed generation costs *increased by 10 percent*.[116] In other words, by using 2008 as its starting point,

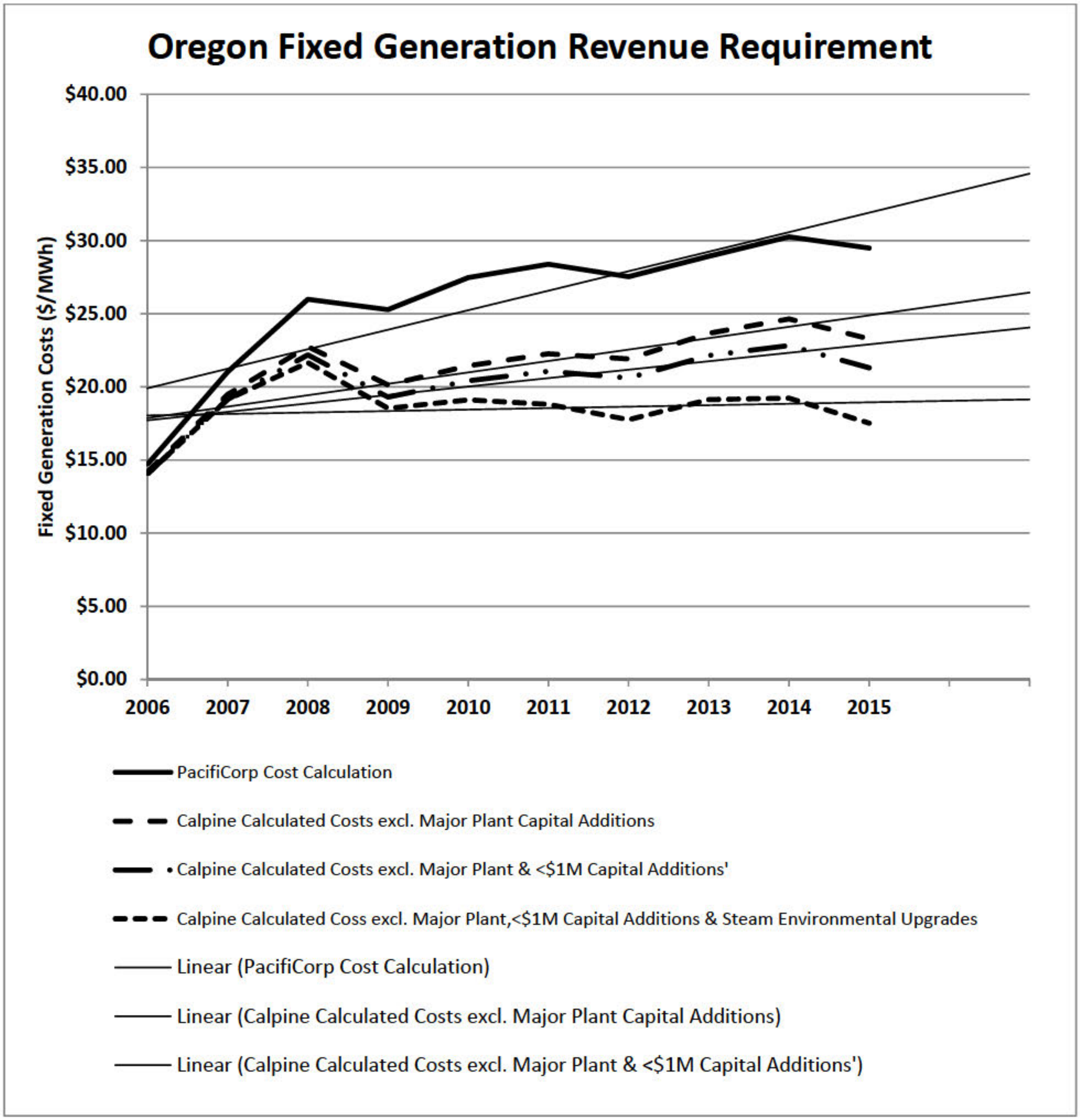
[113] *Re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-out*, Docket No. 267, Order No. 15-060 (Feb. 24, 2015).
[114] Calpine Solutions/200, Higgins/19.
[115] Calpine Solutions/100, Higgins/35 (comparing 2008 to 2015 costs).
[116] Calpine Solutions/105.

Calpine was able to mischaracterize the data and imply that PacifiCorp's fixed generation costs had declined.

Q. Does Calpine's Exhibit 105 actually show this increase in fixed costs?

A. Yes. Figure 5 below is the "Oregon Fixed Generation Revenue Requirement" figure included in Calpine Solutions/105, with trend lines included. The trend lines all show increasing costs for every scenario modeled by Calpine.

FIGURE 5



Q. Did Calpine provide any basis for beginning in 2008?

A. No. Calpine questioned the use of data from 2006, but provided no explanation for using 2008, instead of 2007 or 2009. The only apparent basis for using 2008 is that the fixed generation costs that year were abnormally high compared to the other years in the data set and therefore created an abnormally low growth rate when compared to 2015.

Q. Do you have any other concerns with how Calpine presented its results?

A. Yes. Calpine calculated three different variations of PacifiCorp's fixed generation costs without incremental generation—one that excluded only major capital additions (which appear to be all additions greater than $1 million), one that excluded all capital additions, and one that excluded all capital additions, including environmental upgrades. Calpine appears to rely on the calculation that removed *all* capital additions for its primary analysis. As noted above, even using that metric, PacifiCorp's fixed generation costs increased after incremental investments were removed. But a more reasonable metric is the analysis that removed only *major* capital additions because those investments represent new resources that could theoretically be avoided due to the departure of direct access load.

Q. Does Calpine's analysis removing only major capital additions demonstrate that PacifiCorp's fixed generation costs decrease over time?

A. No. On the contrary, Calpine's analysis verifies the use of an inflation adjustment to keep fixed generation costs constant in real terms.[117] For example, between 2006 and 2015, PacifiCorp's fixed generation costs without incremental generation resources increased by 64 percent, or 5.65 percent annually. To account for the vintage of the 2006 data by adding an additional year,[118] the annual growth rate decreases to 5.07 percent—still more than twice the inflation adjustment used by PacifiCorp.

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[117] The following analysis is based on Calpine Solutions/105.

[118] Calpine argues that 2006 should be excluded because the data is two years removed from 2007 and is therefore not comparable to the other figures in the time series. Calpine Solutions/100, Higgins/35.

Excluding 2006, between 2007 and 2015, PacifiCorp's fixed generation costs without incremental generation resources increased by 19 percent, or 2.25 percent per year. Between 2009 and 2015, fixed generation costs without incremental generation resources increased by 15.6 percent, or 2.45 percent per year.

Q. Do you agree that the Consumer Opt-Out Charge, as currently calculated, includes incremental generation expenses?

A. No. The figures set forth above demonstrate that even when new generation resources are removed, PacifiCorp's fixed generation costs increase. Thus, the increase in the Consumer Opt-Out Charge in years six through 10 reflects non-incremental fixed generation costs, which is contrary to Calpine Solutions' claims. Moreover, the annual compound growth rate of the historical time series verifies the reasonableness of the Commission's approval of an inflation adjustment to years six through 10.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE 323
Exhibit PAC/801
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Michael G. Wilding

List of Proposed Adustments

August 2017

Oregon 2018 TAM
List of PacifiCorp, Staff, and Intervener Adjustments
($ - Millions)

vs. Initial TAM Filing - Oregon Allocated (24.18%)

	PacifiCorp [a]	Staff	CUB	ICNU	Sierra Club	Calpine
EIM Benefits	2.61	3.43				
DA/RT Adjustment [b]		3.08		6.34		
Economic Shutdown of Coal		0.75				
Jim Bridger SCR		Accepted	Accepted			
Cholla LDs		0.27				
QFs		0.12				
Naughton Dispatch					Dropped	
Backcast Analysis of GRID Model		X		X		
Investigation into PCAM Modifications	X					
DA/RT Collar	X	X	X			
Inclusion of Variable O&M in GRID	X	X			X	
Coal Contracts					X	
Transition Adjustment - REC Value				X		X
Transition Adjustment - Schedule 200 Escalation						X

vs. Initial TAM Filing - Total Company

PacifiCorp	Staff	CUB	ICNU	Sierra Club	Calpine
10.80	14.2				
	12.8		26.2		
	3.1				
	Accepted	Accepted			
	1.1				
	0.51	Not Quantified			
				Dropped	2.4

[a] This is the adjustments made by PacifiCorp is response to parties' direct testimony.
[b] This is Staff's estimated adjustment to account for arbitrage transactions. The Company reply to Staff's initial proposal to adjust DA/RT for arbitrage transactions was not rebutted.

Oregon 2018 TAM
List of PacifiCorp, Staff, and Intervener Adjustments
($ - Millions)

vs. Reply TAM Filing - Oregon Allocated (24.18%)

	PacifiCorp	Staff	CUB	ICNU	Sierra Club	Calpine
EIM Benefits		1.26				
DA/RT Adjustment [a]		4.04		6.33		
Economic Shutdown of Coal		0.75				
Jim Bridger SCR		Accepted	Accepted			
Cholla LDs		0.27				
QFs	0.20	0.23	0.35			
Naughton Dispatch					Dropped	
Backcast Analysis of GRID Model		X		X		
Investigation into PCAM Modifications	X					
DA/RT Collar	X	X	X			
Inclusion of Variable O&M in GRID	X	X			X	
Coal Contracts					X	
Transition Adjustment - REC Value				X		X
Transition Adjustment - Schedule 200 Escalation						X

vs. Reply TAM Filing - Total Company

PacifiCorp	Staff	CUB	ICNU	Sierra Club	Calpine
	5.2				
	16.7		26.2		
	3.1				
	Accepted	Accepted			
	1.1				
0.85	0.96	1.46			
				Dropped	

[a] Staff's adjustment is the impact of eliminating the volume component of the DA/RT adjustment. Staff has proposed various adjustments to the DA/RT adjustment though not all have been quantified and some are alternative proposals.

Docket No. UE 323
Exhibit PAC/900
Witness: Kelcey A. Brown

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of Kelcey A. Brown

August 2017

SURREBUTTAL TESTIMONY OF KELCEY A. BROWN

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ATTACHED EXHIBITS

Exhibit PAC/901 – Portland General Electric Company Energy Imbalance Market Report

Exhibit PAC/902 – Idaho Power Company Energy Imbalance Market Report

Q. Are you the same Kelcey A. Brown who previously submitted reply testimony in this Transition Adjustment Mechanism (TAM) 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 testimony in this proceeding?

A. The purpose of my testimony is to support PacifiCorp's forecast of benefits from its participation in the Energy Imbalance Market (EIM) with the California Independent System Operator Corporation (CAISO) for calendar year 2018, which was provided in my reply testimony. I respond to rebuttal testimony from Public Utility Commission of Oregon Staff witness Mr. Scott Gibbens (Staff), in which Staff continues to erroneously claim that PacifiCorp's methodology for estimating inter-regional EIM benefits does not account for historical upward trend.

Q. Please summarize your testimony.

A. PacifiCorp's forecast of its 2018 EIM benefits, as adjusted in the July TAM update to reflect the Company's new forecast methodology and most recent historical data, is reasonable and captures substantial new benefits for customers. In my reply testimony, PacifiCorp estimates total-company inter-regional EIM benefits of [redacted]—an increase of 51 percent over the benefits estimated in PacifiCorp's initial filing and an increase of 45 percent over the most recent 12 months of actual inter-regional benefits. The Company's updated forecast reflects new participants in the EIM, operational changes made at the company's plants to better achieve EIM benefits, and changes made by the CAISO to EIM operations.

PacifiCorp's growth rate produces results that are nearly identical to Staff's original methodology, once Staff corrected and updated its EIM benefits calculation. In rebuttal, however, Staff modified its methodology to offset the impact of these corrections so that Staff's overall adjustment remained nearly unchanged. Staff's new methodology has no evidentiary support, is premised on double-counting growth forecasts, and is unreasonable.

SURREBUTTAL TESTIMONY

Q. Has PacifiCorp updated its inter-regional EIM benefits forecast since filing reply testimony?

A. No. PacifiCorp continues to forecast inter-regional EIM benefits of [redacted] for 2018. PacifiCorp will update its EIM benefits forecast in the TAM final update.

Q. How does PacifiCorp's forecast compare to historical actual inter-regional benefits?

A. PacifiCorp's estimated 2018 inter-regional benefits are substantially higher than historical results. The 2018 forecast is nearly three times higher than 2015 actual benefits, 73 percent higher than 2016 actual benefits, and 45 percent higher than the most recent 12 months.

Q. Has any party other than Staff questioned PacifiCorp's 2018 EIM benefit forecast?

A. No. Contrary to the implication in Staff's testimony,[1] no party other than Staff has contested PacifiCorp's estimate of EIM benefits. In fact, in its opening testimony, the Citizens' Utility Board of Oregon (CUB) supported PacifiCorp's EIM inter-regional

[1] Staff/400, Gibbens/5 (noting the majority of parties took issue with the same adjustments as Staff).

benefits “as an improved methodology of forecasting”[2] relative to how it modeled EIM benefits in previous TAM filings.

Q. Please explain Staff’s most recent arguments that PacifiCorp’s calculation of 2018 EIM benefits is unreasonable.

A. Fundamentally, Staff argues that PacifiCorp’s inter-regional benefit calculation has a “glaring deficiency” because it “does not consider any growth rate or trend in EIM benefits.”[3] Staff claims that PacifiCorp relied on a “naïve forecast” that used purely historical data and then made “minor adjustments.”[4]

Q. Is it true that PacifiCorp did not consider any growth rate when forecasting 2018 inter-regional benefits?

A. No. PacifiCorp’s inter-regional EIM benefits are 45 percent higher than the most recent 12 months of actual data. PacifiCorp did not utilize a naïve forecast, which is a forecasting technique that utilizes a prior period actuals without adjusting them or attempting to establish causal factors. Instead, PacifiCorp modeled growth by more heavily weighting more recent EIM data—reflecting the latest efficiency gains and actual results—and by including a [redacted] adjustment to account for the participation of new entrants Portland General Electric Company (PGE) and Idaho Power Company (Idaho Power), and the over-supply conditions in California caused by increased solar generation.

Q. How does PacifiCorp’s proposed growth rate compare to Staff’s?

A. Staff recommends a 51 percent growth rate, which is nearly the same as

[2] CUB/100, Jenks/14.
[3] Staff/400, Gibbens/9, 16.
[4] Staff/400, Gibbens/9-10.

PacifiCorp's.[5] Staff's testimony never acknowledges the substantial growth rate embedded in PacifiCorp's calculations or explains why a 45 percent growth rate is entirely unreasonable, but a 51 percent growth rate is not.

Q. Did Staff's methodology for calculating inter-regional EIM benefits change in its rebuttal testimony?

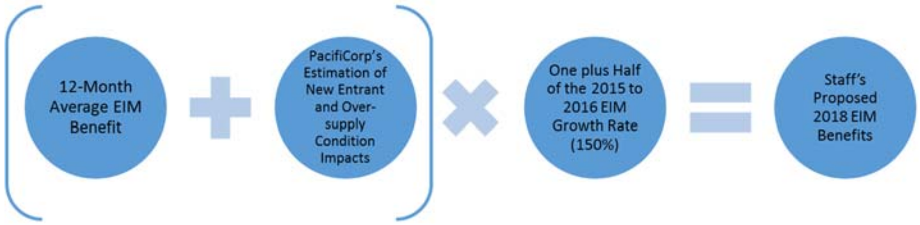
A. Yes, although Staff's testimony implies otherwise. Staff testifies that its revised "adjustment maintains the reasoning behind Staff's original adjustment but corrects for the [greenhouse gas] inclusion and updates the data to the most current validated actuals."[6] Notably, Staff's original methodology used in its opening testimony produces inter-regional EIM benefits of [redacted] (when corrected and updated)[7]—a nearly identical forecast to PacifiCorp's [redacted]. Had Staff just corrected and updated its original position, Staff's EIM adjustment would be approximately [redacted]. Instead, Staff is now proposing an adjustment of approximately [redacted].

Q. How did Staff's methodology change in its rebuttal testimony?

A. Staff included an additional adjustment for new market entrants and increased solar penetration in California. As shown in Figure 1, Staff now uses a 12-month historical average, adds PacifiCorp's adjustment for new entrants (which Staff argues is an inaccurate "guesstimate"), and then grosses up both of those amounts by one-half of the year-over-year growth rate based on the most recent 12 months.

[5] Staff's 51 percent growth rate is calculated as 50 percent of the year-over-year growth rate for the most recent 12 months of verified EIM results.
[6] Staff/400, Gibbens/17-18.
[7] This estimate accounts for Staff's initial error that included the greenhouse gas revenues in its gross-up of inter-regional benefits and used the average of the monthly averages, as opposed to an annual average. PAC/500, Brown/10-11 discusses the difference between using an annual average versus an average of the monthly averages.

FIGURE 1



Based on this new methodology, Staff calculates inter-regional EIM benefits of [redacted] for 2018, which is 25 percent higher than PacifiCorp's estimate.

Q. How did Staff account for new market entrants in its original methodology?

A. Staff's original methodology accounted for new market entrants by applying 50 percent of the year-over-year growth rate to the most recent 12 months of actual EIM data.[8] Staff's historical growth rate accounts for the participation of new market entrants because those benefits are embedded in the historical results—which is why Staff's original methodology did not have a separate, external adjustment for new market entrants.

Staff's new methodology applies the same 50 percent of the year-over-year growth rate to the most recent 12 months of actual EIM data and then adds a separate, incremental [redacted] adjustment for new participants and over-supply conditions. Thus, Staff's new methodology effectively double counts the impact of new market entrants.

Q. Does Staff criticize PacifiCorp's calculation of the benefits resulting from new market entrants?

A. Yes. Staff testifies that PacifiCorp's calculation is "arbitrary in that [it is] not based

[8] Staff/100, Gibbens/11.

on an informed study, but rather a 'best guess' to be added to the benefit calculation."[9] Staff continued that, "[i]nstead of attempting to guesstimate a complex issue, Staff believes that a data-driven approach to resolving an issue which has to be solved is the more rational approach."[10] These criticisms are undermined by Staff's use of PacifiCorp's so-called "guesstimate" in Staff's own forecast. If Staff truly believed PacifiCorp's estimate was arbitrary, it is difficult to understand why Staff used it to estimate nearly 17 percent of its EIM benefits. Staff does not reconcile its conflicting positions on this issue.

Q. Is the methodology PacifiCorp used to calculate benefits for new market entrants arbitrary?

A. No. PacifiCorp calculated [redacted] in 2018 benefits resulting from PGE's market entry and [redacted] resulting from Idaho Power's market entry.

Q. How do PacifiCorp's forecast benefits for new entrants compare to the benefits estimated by Energy and Environmental Economics, Inc. (E3)?

A. PacifiCorp's benefit forecast is higher. PGE's most recent E3 study estimated that PGE's participation in the EIM would produce annual benefits of $1.2 million for every other market participant.[11] Idaho Power's E3 study estimated annual benefits of $2.9 million for every other market participant.[12] PacifiCorp estimates [redacted] in 2018 benefits, while the E3 studies estimate $3.375[13] million *for every market participant*. The fact that PacifiCorp is modeling greater benefits than E3

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[9] Staff/400/Gibbens/9.
[10] *Id.*
[11] PAC/901.
[12] PAC/902.
[13] Idaho Power is currently scheduled to join the EIM April 1, 2017, therefore, the $3.375 million includes the $1.2 million estimated for EIM participants from the joining of PGE and 75 percent of the $2.9 million, or $2.175 million.

undermines Staff's claim that PacifiCorp forecast is unreasonably low; it also shows that Staff's adjustment is unreasonably high.

Q. Does PacifiCorp expect that PGE's and Idaho Power's entry into the EIM will produce the same level of benefits as prior entrants?

A. No. While import and export volumes increased by over 80 percent after the entry of Arizona Public Service Company (APS) and Puget Sound Energy (PSE) in the EIM, part of this increase was due to higher volumes of negative intervals in the spring of 2017 versus 2016. In addition, the average margin that PacifiCorp was able to earn during this period decreased by 17 percent.

In 2018, PacifiCorp does not expect that PGE or Idaho Power will provide the same increase in volumes because there is no additional transmission connectivity with the CAISO through the PacifiCorp East Balancing Area and limited additional connectivity through PacifiCorp West Balancing Area. As shown in Figure 2 below, PacifiCorp also anticipates a similar decline in its average margin, due to additional market depth and price stabilization, and an approximately 21 percent increase in transfer volumes.

FIGURE 2

New Entrant Statistical Information		
	Forecast	**Growth Rate**
New Entrants Plus Solar PacifiCorp Adjustment	[redacted]	
Average Margin ($/MWh)	[redacted]	-17%
Average Monthly Volume Change (MWh)	87,810	21%

Q. Can you please describe the transmission connectivity that you expect PGE to bring once it enters the EIM in October 2017?

A. PGE is expected to bring approximately 300 MW of static transmission capability to the CAISO but only a limited amount of dynamic transfer capability (likely less than 100 MW). For comparison, APS has allowed PacifiCorp to import over 900 MW and export 600 MW (no dynamic transfer limitations) through its transmission connectivity to the PacifiCorp East balancing area. In addition, the APS and NV Energy, Inc. (NV Energy) transmission connections avoid the Northern to Southern California transmission constraints and allow PacifiCorp to access the Southern California market solar generation and high third-quarter demand.

Q. Is Staff's recommendation for the EIM benefits based on the "data-driven approach" it testifies is necessary?

A. No. As noted above, Staff utilized PacifiCorp's estimated impacts of new entrants and California over-supply conditions and then simply multiplied it by 50 percent of a historical growth rate. Staff never explains why it is not double-counting by adding a growth rate on top of PacifiCorp's new entrant adjustment, which is itself designed to forecast the growth of EIM benefits in 2018.

Q. Taking into consideration Staff's use of PacifiCorp's estimated EIM impacts for new entrants and over-supply conditions, what is the actual growth rate that was applied to the historical EIM benefits?

A. Staff calculated inter-regional EIM benefits of [redacted] for April 2016 through March 2017, based on actual benefits. If PacifiCorp's new market entrants and over-supply adjustment is removed from Staff's calculations, Staff applied an 81 percent growth rate to historical inter-regional EIM benefits to reach total inter-regional EIM benefits of [redacted]. Staff testified that its 51 percent growth rate was reasonable to account for "the potential that the trend is greatly diminished, and found a middle ground between two alternative possibilities; the first being that the trend has completely stopped, the second that the trend will continue as it has."[14] This rationale does not apply to the effective 81 percent growth rate Staff applied to historical results nor does this "middle ground" approach rely on any data related to actual market trends.

Q. Staff also claims that PacifiCorp's 2016 forecast of EIM benefits was less than actual benefits.[15] How do you respond?

A. PacifiCorp's 2016 forecast was below actual EIM benefits primarily because of limited EIM operational data available through October 2015—less than one year into the market—and no operational experience related to additional entrants in the EIM. At that time, PacifiCorp relied on the most accurate evidence available to estimate benefits in a new market. In the 2016 TAM, Staff acknowledged that PacifiCorp "made notable and creative efforts to estimate EIM benefits" based on limited data and made the "general observation" that PacifiCorp's "approach [was] not unreasonable."[16] Staff also specifically concluded that PacifiCorp's estimated benefits for new market participants was reasonable.[17]

Q. In the 2016 TAM, how did PacifiCorp estimate the impact a new entrant would have on PacifiCorp's EIM benefits?

A. At the time, due to no market experience with new entrants, PacifiCorp utilized its E3 study to estimate the impact of new entrants in the EIM. The primary reason that

[14] Staff/400, Gibbens/14.
[15] Staff/400, Gibbens/15.
[16] Docket No. UE 296, Staff/100, Ordonez/12-13.
[17] Docket No. UE 296, Staff's Response Brief at 10.

PacifiCorp's 2016 forecast was less than actuals was because the benefits from NV Energy joining the market in late 2015 were higher than what E3 projected.

Q. Did PacifiCorp use the E3 study to estimate the impact of new market entrants in the 2017 TAM?

A. PacifiCorp did use the E3 study in its initial filing. In its reply filing, however, the company updated the forecast for new entrants with actual EIM data reflecting the incremental benefits of APS and PSE joining the EIM in 2016. Using the E3 study, the initial filing estimated additional benefits due to new entrants of only [redacted]. When PacifiCorp used actual data and its own analysis, it estimated incremental benefits of [redacted] resulting from new entrants.

Q. Why did the E3 study underestimate the impact that a new entrant to the EIM might have on PacifiCorp's EIM benefits?

A. The E3 study utilized information that was available at the time the study was performed to attempt to estimate the benefits that PacifiCorp might realize with more economic dispatch across a broader region. E3 did not anticipate the changes in the market relative to California's continued growth in over-supply conditions, and the specific dynamics that each entrant might have relative to transmission and resource portfolios.

Q. Does PacifiCorp's reply filing using EIM benefit data from October 2016 through March 2017, fully capture the changes in the market relative to the new entrants, and California's over-supply conditions?

A. Yes. PacifiCorp's historical market data takes into consideration the participation of APS and PSE, as well as the increase in negative pricing intervals in the winter and spring of 2017, and is a good representation of EIM benefits in the future. Figure 3 below illustrates the change in average monthly volume in exports and imports, as well as the average EIM benefit margin per MWh captured for the October 2016 – March 2017 period versus January 2016 – September 2016 period.

FIGURE 3

EIM Average Monthly Volume and Marginal Benefit			
EIM Direction	January 2016 - September 2016	October 2016 - March 2017	Percentage Growth
Export (MWh)	151,337	272,736	80%
Import (MWh)	(81,303)	(153,508)	89%
Total (MWh)	232,640	426,244	83%
[redacted]			

Q. Staff questioned PacifiCorp's use of historical EIM benefit data versus utilizing a more sophisticated forecast model.[18] Why doesn't PacifiCorp employ a regression model similar to what it does to forecast load?

A. PacifiCorp's load forecast utilizes a regression model that relies on independent variables that are also forecasts, such as gross domestic product, population growth and employment. As stated in my reply testimony, the EIM does not have a forward price curve because it is an intra-hour market that reflects the marginal cost of a resource that is available within the hour. Prices might swing from negative $10 per MWh in one five-minute interval to positive $85 per MWh the next five-minute interval due to changes in renewable generation, load and the ramp rate of the units that are operating. There is no independent variable that causes PacifiCorp's EIM benefits to be higher or lower in a given year.

[18] Staff/400, Gibbens/9.

Q. Staff argues that PacifiCorp has relied on anecdotal evidence to support its claim that the historical growth in EIM benefits is not likely to continue into 2018.[19] How do you respond to these arguments?

A. PacifiCorp relies on expert testimony, not "anecdotal" evidence. My testimony is based on extensive experience managing the company's participation in the EIM, analyzing the benefits that have been achieved to date, and monitoring the changes in the market dynamics that will inform future benefits. Moreover, in my reply testimony, I explained that PacifiCorp's operational constraints, such as generation plant minimums and maximums, would eventually limit the company's ability to continue to realize the growth in EIM benefits experienced in the past. Physical plant constraints, such as the operating minimums of a facility, are not anecdotal evidence.

Q. Staff disputes PacifiCorp's claim that the historical growth rate Staff uses to forecast inter-regional benefits is unsustainable.[20] How do you respond?

A. Staff argues that it is literally impossible to show that there are no additional efficiency gains that can be made.[21] PacifiCorp disagrees that there is no way to determine if additional efficiency gains will be achieved, or to provide a reasonable estimate of those gains. PacifiCorp's experience in the market provides a reasonable basis for determining whether additional efficiency gains are possible and how those gains will likely compare to those achieved in the past. Thus, PacifiCorp has estimated an increase in 2018 inter-regional benefits of 45 percent over the most recent 12-month period.

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[19] *See, e.g.*, Staff/400, Gibbens/11.
[20] Staff/400, Gibbens/11.
[21] *Id.*

Q. Staff states that PacifiCorp's generation plant capability is not the only way that PacifiCorp could realize additional EIM benefits; there may be changes in price in the EIM that could produce additional benefits.[22] Do you agree with Staff's point that changes in price can cause additional benefits?

A. Yes. In fact, PacifiCorp's EIM estimated impact of continued over-supply conditions is related to the expectation that EIM import prices in 2018 will be lower relative to the volume of imports that PacifiCorp was able to realize in the fourth quarter of 2016 and the first quarter of 2017. This is tempered by the fact that additional entrants into the market will allow greater absorption of the low-cost renewable power, which will allow the CAISO to avoid curtailing its renewable output and keep prices relatively constant.

Q. Do you expect PacifiCorp to continue to make operational improvements to provide additional flexibility in the market?

A. Yes. The changes, however, will be less significant, such as decreasing a plant minimum by a few megawatts as our plant operators continue to fine-tune the boiler of each coal facility to maintain reliable operations at lower operating levels. The changes made in 2016 to decrease minimum operating levels are what the plants can achieve without making capital investments to stabilize the boiler flame and keep the temperature of the air hot enough for the production of steam.

Contrary to Staff's representations, my testimony did not indicate that there are *no* additional operating efficiencies. I testified that PacifiCorp does not anticipate

[22] Staff/400, Gibbens/13-14.

achieving any *significant* operational efficiencies, comparable to the changes made in late 2016 that would affect the inter-regional benefits in 2018.

Q. In addition to dismissing PacifiCorp's argument that its facilities have physical operational constraints, Staff believes that PacifiCorp's proposed benefits ignore a growth trend in EIM benefits.[23] Is there any additional analysis that verifies PacifiCorp's position that historical growth rates are unlikely to be achieved in 2018?

A. Yes. The CAISO has published an EIM benefit calculation for each EIM entity every quarter since January 2015, and recently published its results through June 2017. Figures 4 and 5 below show the growth rates of EIM benefits for PacifiCorp and the CAISO for 2015 to 2016 and, three years of comparable data, January 2015 through June 2017.

FIGURE 4

California Independent System Operator EIM Benefit Calculation			
$ Millions	2015	2016	Annual Growth
CAISO	$12.7	$28.3	124%
PacifiCorp	$26.2	$45.5	73%

FIGURE 5

California Independent System Operator EIM Benefit Calculation				
$ Millions	January - June 2015	January - June 2016	January - June 2017	Annualized Growth Rate
CAISO	$3.9	$14.2	$25.0	153%
PacifiCorp	$11.5	$21.4	$20.4	33%
Nevada		$6.9	$8.1	17%

[23] Staff/400, Gibbens/11.

The annual growth rate in the first year of EIM operations for PacifiCorp and the CAISO do show considerable growth rates in EIM benefits; however, for PacifiCorp in the first half of 2017, its EIM benefits have declined relative to the prior year and the CAISO's benefits appear to have increased.

Q. What would cause the CAISO benefits to continue to rise while PacifiCorp's have flattened?

A. As explained in my reply testimony, PacifiCorp's ability to continue to realize benefits is constrained by the physical operating parameters of its facilities, as well as the possibility that new entrants can actually cause a decline in EIM benefits for the company due to the unique attributes that each EIM entity makes available to the market. The CAISO's continued increase in EIM benefits is further evidence of this point, due to the fact that the CAISO has a significantly larger pool of resources (over 50,000 MW), and over 3,500 MW of transmission interconnections with PacifiCorp, APS, and NV Energy.

Q. Does the CAISO EIM benefit calculation for PacifiCorp also include intra-regional benefits, inter-regional benefits, diversity benefits, and greenhouse gas benefits?

A. Yes. The CAISO's EIM benefit calculation for PacifiCorp includes all of the components of the EIM benefits, including greenhouse gas benefits, which have continued to increase year-over-year.

Q. Is it likely that intra-regional benefits or diversity benefits have declined, causing the decline in the first half of 2017 versus the first half 2016 EIM benefits shown in the figures?

A. No. PacifiCorp has not changed how it schedules its resources internally, and it is likely that PacifiCorp's intra-regional benefits have actually increased due to more solar generation in the PacifiCorp East Balancing Area and PacifiCorp's ability to more efficiently integrate renewables with its own facilities.

Q. If the CAISO's calculation of PacifiCorp's EIM benefits is flattening or declining, why has PacifiCorp proposed a 45 percent increase in EIM benefits?

A. PacifiCorp believes that it will have continued opportunities in the EIM that allow it to realize additional benefits on behalf of its customers relative to the new entrants into the market, as well as continued impacts of over-supply conditions in the CAISO. However, PacifiCorp recognizes that there will be challenges due to plant limitations that will require it to continue to improve its operations in order to realize this growth in EIM benefits in 2018. As discussed previously, the improvements in operations that PacifiCorp is able to realize moving forward are likely to be smaller. These benefits will require PacifiCorp to leverage the voluminous data that is available in the market, and continue to improve operations of existing facilities.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE 323
Exhibit PAC/901
Witness: Kelcey A. Brown

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Kelcey A. Brown

Portland General Electric Company Energy Imbalance Market Report

August 2017

PGE Energy Imbalance Market Addendum: 2018 Scenario

November 2016

PGE Energy Imbalance Market Addendum: 2018 Scenario

November 2016

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Table of Contents

Executive Summary

Portland General Electric Company (PGE) engaged E3 to conduct an updated study for year 2018 to model the projected economic benefits of PGE's participation in the CAISO EIM. As with the 2020 study, this study seeks to identify the gross savings potential of PGE's participation in the CAISO EIM, and does not investigate the initiation, labor, or operating costs associated with an EIM. The analysis methodology used is consistent with the EIM study that E3 completed for PGE in 2015 (which was based on a 2020 study year).[1]

Similar to the earlier EIM study for PGE, this current analysis uses production simulation modeling in PLEXOS to estimate PGE's benefits resulting from participation in the EIM. The analysis compares PGE's real-time generation costs as an EIM participant, as well as any revenues or costs from transactions with other EIM participants, against those of a business-as-usual (BAU) case in which PGE does not participate in the EIM.

The BAU simulation case includes operations of a "current EIM", consisting of an updated set of seven other BAAs assumed to be also participating in

[1] See E3, PGE EIM Comparative Study: Economic Analysis Report, November 2015, Published as Appendix B of PGE Report "Comparative Analysis of Western EIM and NWPP MC Intra-Hour Energy Market Options", (http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf)

the EIM in 2018. These EIM participants (other than PGE) are listed in the table below.

This 2018 analysis indicates that EIM participation is projected to create $4.2 million in dispatch savings for PGE (compared to a BAU case in which PGE does not participate) as well as $1.0 million in additional savings from pooling of flexible reserves.

Table 1: BAA Participants in EIM in 2018 BAU Case

Current EIM participants for BAU Case
Arizona Public Service (APS)
CAISO
Idaho Power Company (IPC)
PacifiCorp East (PACE)
PacifiCorp West (PACW)
NV Energy (NVE)
Puget Sound Energy (PSE)

1 Study Assumptions and Approach

Portland General Electric Company (PGE) engaged E3 to conduct an updated study for year 2018 to model potential economic benefits of PGE's participation in the CAISO EIM. As with E3's 2015 EIM study for PGE (which focused on the 2020 study year), this study seeks to identify the savings potential of PGE's participation in the CAISO EIM.

1.1 Input Data Changes

The PGE EIM 2020 study base case database was used as the starting point dataset used for this updated 2018 analysis. That 2020 study database was updated to reflect differences in the expected topology and operating conditions in 2018 versus 2020. The updates for this 2018 analysis are described in more detail below and summarized in Table 2 and the updated real time transfer capability is shown in Figure 1.

+ **Topology updates.** Transfer limits were updated on the PG&E Valley to PGE and on the PacifiCorp West to PGE lines to reflect PGE's anticipated transfer capabilities for the year 2018. [2]

+ **Gas prices.** Gas prices were updated based on 2018 monthly forward hub prices from August 2016. Consistent with the methodology in the 2020 report, gas hub prices are translated to BA- and plant-specific burner tip prices using estimated zone-specific delivery charges developed for the NWPP EIM Study.[3]

+ **Generation updates.** At PGE's direction, E3 updated several plants in PGE's generation fleet to reflect their status in 2018. E3 modified the status of Boardman Plant, scheduled to close in 2020, to be included in 2018 and used data from PGE to update the unit's start-up cost, maximum ramp up and down, minimum down time, heat rate, maximum capacity, and minimum stable level. Additionally, E3 included the Wells Hydro Project as part of the portfolio of Mid-C hydropower generation shares to reflect PGE's expectation (as of the initiation of this study) regarding potential expiration of contracts in August 2018 for PGE and other EIM participants.

+ **Renewable generation updates.** E3 scaled renewable generation by BAA to match to data available for units in WECC TEPPC 2026 and expected to be online by 2018. E3 cross-referenced this data with renewable generation reports in EIM

[2] Compared to the original 2020 study base case, CAISO to PGE transfer capability was increased from 450MW to 600 MW; PACW to PGE transfer capability was decreased from 448MW to 276MW and PGE to PACW transfer capability was decreased from 448MW to 306MW. Original 2020 transfer capabilities can be found in E3's 2015 PGE EIM Comparative Study.

[3]The NWPP EIM study was published in October 2013 and can accessible at: http://www.nwpp.org/documents/MC-Public/NWPP_EIM_Final_Report_10_18_2013.pdf

participants' IRPs when possible. In the CAISO territory in California, the resource mix was updated to reflect currently projected renewable generation levels for 2018 based on CAISO and CEC data. As with the 2020 database, estimates of rooftop PV are included in CAISO solar. PGE provided updates for its forecasted levels of wind generation for 2018.

+ **Load updates.** Loads were updated for each BAA by scaling monthly energy to forecasted levels reported in the WECC Load and Resources (LAR) data 2016 submittals by Western BAAs, with the exceptions of PGE and CAISO. PGE load was scaled to monthly energy totals provided by PGE staff. In CAISO, load was scaled to monthly forecasts from the CEC IEPR 2015. Overall, WECC load forecasts have been reduced in the 2018 case compared to the 2020 database, both due to the nearer year to model (2018) and the more updated vintage of load forecast data which typically reflects slower WECC load growth.

Figure 1. Real-time Transfer Capabilities across the CAISO EIM with PGE Footprint

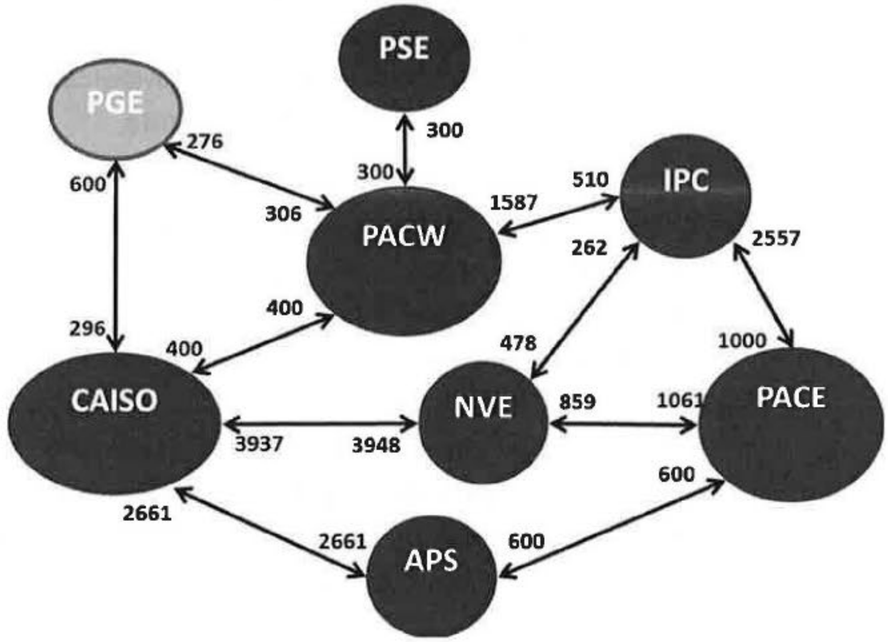


Table 2. Summary of Input Data Modification between the 2018 and 2020 EIM Study

	PGN Portfolio		EIM Members Portfolio and WECC Portfolio	
Scenario year	**2018**	**2020**	**2018**	**2020**
Load	Provided by PGE; 14.4% reduction on average from 2020 to reflect 2018 and newer data	From NWPP EIM Study by PNNL from 2013; load forecast based on TEPPC 2020 PCO scenario	Scaled for 2018 to WECC Load and Resource data based on 2016 submittals by BA; generally lower than 2020 data	From NWPP EIM Study by PNNL from 2013; load forecast based on TEPPC 2020 PCO scenario
Gas Price	PGE August 2016 projection of 2018 monthly forward prices for Western hubs	PGE Q2 2015 projection of 2020 monthly forward prices for Wes tern hubs	PGE August 2016 projection of 2018 monthly forward prices for Western hubs	PGE Q2 2015 projection of 2020 monthly forward prices for Western hubs
Generation	Boardman plant online	Boardman assumed retired; 400MW gas replacement	--	--
	Wind Portfolio is 717 MW	Wind portfolio is 1074 MW	EIM participants' wind and solar scaled to best information from IRPs and TEPPC 2026 Common Case generator list; CA updates from E3 & CEC solar projections	NWPP EIM study report data updated for certain BAAs based on technical review; CA updated to newer projections
	PGE Wells' contracted output included Jan. – Aug.	PGE's contracted output removed for full study year	AVA, PACW, PSE contracted output included Jan. – Aug.	AVA, PACW, PSE contracted output included for full year
	Colstrip units 3 and 4 not dispatchable in real time	Colstrip units 3 and 4 dispatchable in real time including to the EIM	EIM participants' shares of Colstrip 1-4 not dispatchable in real time	Colstrip ownership shares dispatchable in real time to owners' BAAs.
Transmission	Max transfer from PGE to PacifiCorp West (PACW) updated to 306 MW; max transfer from PACW to PGE updated to 276 MW	Max transfer from PGE to PACW limited to 448 MW; max transfer from PACW to PGE limited to 448 MW	EIM connections added to Idaho Power Company and Arizona Public Service	EIM connections reflected in diagram included in 2020 EIM study report
	Max transfer from COB to PGN updated to 600MW; max transfer from PGE to COB remains 296 MW	Max transfer from COB to PGE limited to 450 MW; max transfer from PGE to COB limited to 296 MW	--	--
EIM participants before PGE joins	--	--	Arizona Public Service (APS), California ISO, Idaho Power Company (IPC), NV Energy (NVE), PacifiCorp (PACW & PACE), Puget Sound Energy (PSE)	California ISO, NV Energy (NVE), PacifiCorp (PACW & PACE), Puget Sound Energy (PSE)

2 EIM Benefit Results

2.1 Benefits to PGE

Table 3 below summarizes the simulated annual benefits to PGE from participation in the EIM in 2018. Each column in the table represents the incremental benefit to PGE from participation in the EIM. The first column focuses on dispatch cost savings and assumes no cost savings from flexible reserve pooling, while the second column reports the incremental (additional) cost savings that PGE could realize from flexible reserve pooling. Flexible reserve pooling uses lower reserve requirements to reflect the diversity in load shapes and solar and wind resources across the expanded EIM footprint, including PGE. Monthly diversity factors are produced that reflect PGE's net load contribution to the EIM's monthly average requirements; diversity factors are applied to BA-specific reserve requirements, which are individually calculated. The impact to PGE from pooling flexibility reserves with the rest of the EIM is valued by the increase in benefits in the flexible reserves pooling case versus the dispatch cost savings only case.

Savings (in both the 1st and the 3rd columns) are calculated as the reduction in cost compared to a common BAU case in which PGE does not participate in the EIM. Overall, the cost savings are $4.2 million in the base scenario, and $5.2 million in the scenario with flex reserves savings included, which implies that flex reserves pooling provides PGE with an additional $1.0 million savings compared to the Base Scenario.

Table 3. Annual Benefits to PGE by Scenario, CAISO EIM (2015$ million)

Scenario	Dispatch cost savings to PGE	Additional Cost savings from Flex Reserve Pooling	Total savings including dispatch and reserves
Base	$4.2	$1.0	$5.2

2.2 Incremental Benefits to Current EIM Participants

Table 4 below presents the incremental benefits for the current EIM participants that result from PGE's EIM participation. In addition to savings realized by PGE, PGE's EIM participation is projected to create $1.2 million in savings to the current CAISO EIM participants in the Base Scenario. When PGE participates in the EIM and is also modeled with pooling of flexible reserves, total incremental savings for the current EIM participants (vs. the BAU case with no PGE participation) is instead $0.3 million.

Table 4. Annual Benefits to Current CAISO EIM Participants by Scenario (2015$ million)

Scenario	Incremental savings to Existing EIM Participants	Additional Cost savings from Flex Reserve Pooling	Total savings
Base	$1.2	-$0.9	$0.3

Taken together, these results imply that PGE participation provides positive incremental savings for the current EIM participants in both scenarios—with or without flexible reserve pooling. Also, total savings (for PGE plus the current EIM participants) is slightly higher when PGE is able to pool flexible reserves than in the Base Scenario. However, when PGE pools flexible reserves, PGE realizes a larger share of the total incremental savings from PGE participation (for PGE plus the current EIM participants). Flexible reserve pooling allows PGE to better position its generator commitment in the DA and HA time frame to benefit from the cost savings that the EIM enables in real time. Without pooling flexible reserves to reflect system diversity, PGE may instead hold more reserves in the HA than it needs for its own real-time use, and that extra flexibility available could result in a higher share of benefits available for other EIM participants.

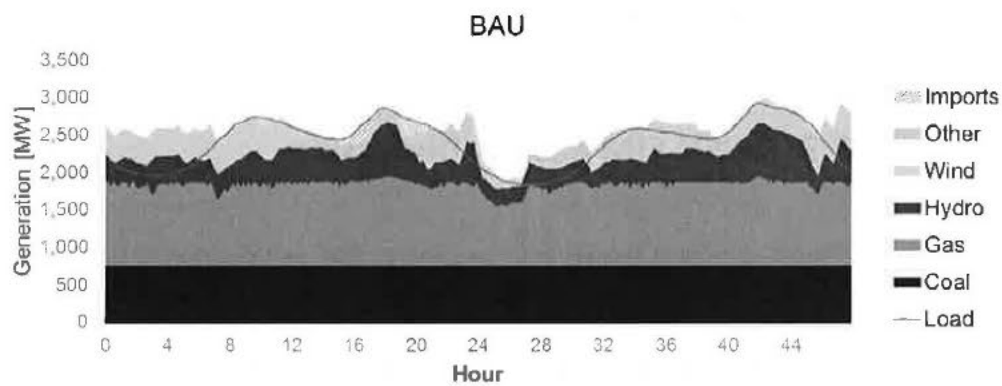
In the simulation studies, flexible reserve savings creates $1 million in additional benefits for PGE compared to dispatch cost savings in the Base Scenario (as shown in Table 4), while flexible reserve pooling results in PGE providing positive but a smaller level of savings to the current EIM participations. As a result, the simulation indicates that the incremental cost savings to current EIM participants (from PGE using flexible reserve pooling) is $0.9 million less than in the Base Scenario where PGE participates in the EIM but does not pool flexible reserves with other participants (as shown in Table 4).

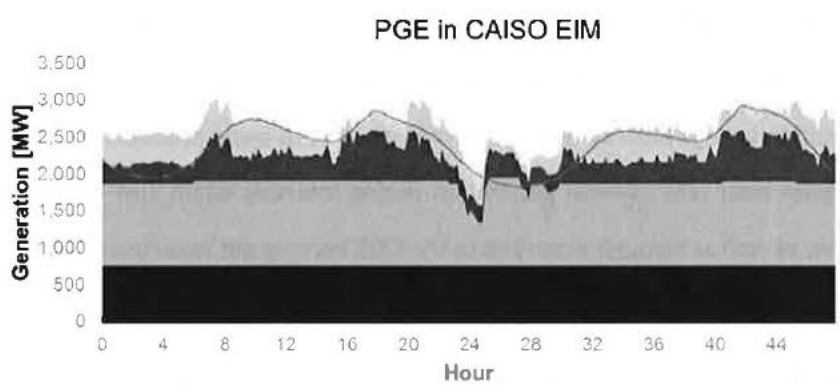
2.3 CAISO EIM Results Discussion

Overall, excluding flexible reserve pooling, PGE participation in 2018 results in $4.2 million of dispatch savings to PGE, as well as $1.2 million in savings to the existing EIM participants for a total of $5.4 million in savings for the EIM as a whole. EIM participation enables PGE to export and import in real time with other EIM participants to respond to intra-hour imbalances in the 2018 case, similar to the patterns observed in the 2020 EIM analysis for PGE. PGE realizes savings both by importing from the EIM to avoid production cost on higher heat rate internal generation during intervals when EIM prices are low, as well as through exporting to the EIM, earning net revenues when EIM prices are higher than PGE's internal cost.

The following chart provides a closer graphical look at the relationship between savings and generation, displaying PGE's dispatchable generation in real time over December 12-13, 2018.

Figure 2. PGE Real-Time Dispatchable Generation, CAISO EIM, December 12-13, 2018





The upper chart shows PGE's dispatch in the BAU scenario, while the lower chart shows how that dispatch changes with PGE in the EIM. Over this two-day period, PGE both imports from and exports energy to neighboring

BAAs who are EIM participants.[4] EIM participation enables greater transaction flexibility. As a result, PGE is able reduce its generation cost by backing down certain gas units during this period.

[4] Imports are identified as the grey area which occurs in intervals where the red line (representing load) exceeds the stacked sum of PGE generation. Exports occur in intervals when the sum of PGE's generation exceeds the load line.

Docket No. UE 323
Exhibit PAC/902
Witness: Kelcey A. Brown

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Kelcey A. Brown

Idaho Power Company Energy Imbalance Market Report

August 2017

An IDACORP Company

Idaho Power Company
Energy Imbalance Market Analysis

February 2016

Energy+Environmental Economics

PLEXOS®
Integrated Energy Model

Idaho Power Company Energy Imbalance Market Analysis

February 2016

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Energy Exemplar

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[redacted]

Acronyms

APS	Arizona Public Service Company
BA	Balancing Authority
BAA	Balancing Authority Area
BAU	Business-as-usual
CAISO	California Independent System Operator
DA	Day-ahead
EIM	Energy Imbalance Market
FERC	Federal Energy Regulatory Commission
HA	Hour-ahead
IPC	Idaho Power Company
LMP	Locational Marginal Price
NVE	NV Energy
NWPP	Northwest Power Pool
PACE	PacifiCorp East
PACW	PacifiCorp West
PGE	Portland General Electric Company
PNNL	Pacific Northwest National Laboratory
PSE	Puget Sound Energy
WECC	Western Electric Coordinating Council

Executive Summary

Over the past year, in an effort to increase operational efficiency and create cost savings for IPC customers, Idaho Power Company (IPC) has been exploring participation in the energy imbalance market (EIM) operated by the California Independent System Operator (CAISO). As part of its assessment of opportunities for regional coordination, IPC engaged Energy & Environmental Economics, Inc. (E3), to analyze the potential economic benefits of IPC's participation in the Western EIM. This report describes the results of our study.

The analysis uses production simulation modeling in PLEXOS to estimate IPC's benefits resulting from participation in the EIM by comparing IPC's real-time generation costs as an EIM participant, as well as any revenues or costs from transactions with other EIM participants, against those of a business-as-usual (BAU) case in which IPC does not participate in the EIM. To focus on the incremental impact of IPC participation, the BAU case includes operations of a "current EIM" consisting of the seven BAAs that were participating or had announced plans to participate in the EIM at the start of this study. These BAAs are listed in the table below.

Table 1: BAA Participants in EIM in BAU Case

Current EIM participants for BAU Case
CAISO
PacifiCorp East (PACE)
PacifiCorp West (PACW)
NV Energy (NVE)
Puget Sound Energy (PSE)
Arizona Public Service (APS)
Portland General Electric (PGE)

Under the Base Scenario simulated for the year 2020, the analysis estimates that EIM participation would produce $4.5 million in annual sub-hourly dispatch cost savings for IPC. Under an alternative scenario with higher renewable buildout in the region, EIM participation created $5.1 million in total sub-hourly dispatch cost savings to IPC. Savings due to reduced flexibility reserves (from the diversity provided by the EIM) were not estimated in this study, but would provide savings in addition to the figures stated above. For example, in a previous study E3 estimated that PGE would receive $0.8 million in savings due to reduced flexibility reserves from joining the EIM.

Table 2. Annual Savings to IPC from Participation in EIM (2015$ million)

Scenario	EIM Savings to IPC
Base Scenario	$4.5
No APS or PGE	$4.2
Early Coal Retirement	$4.1
High RPS Case	$5.1

Overall, this study estimates that participation in the EIM would produce modest positive savings for IPC, and that savings from participation would be larger in the presence of larger renewable resource buildout. In addition to savings to IPC, we also estimate that IPC participation in the EIM would produce over $2 million in incremental savings for the current EIM participants.

Base Scenario savings to IPC are positive and modest due to a combination of factors. Monthly 2020 gas prices came from OTC Global Holding Natural Gas Forwards & Futures (provided by SNL) for selected hubs in the West region; the average price for IPC area generators was $3.27/MMBTU for 2020 (in 2015 dollars). These relatively low gas prices moderated the value of EIM flexibility to IPC. Additionally, IPC's generator portfolio modeled for 2020 includes flexible hydro resources that can respond quickly to changes in sub-hourly needs, making IPC's flexibility needs lower than those of a utility without much flexible generation.

The model's Base Scenario sets California's renewable build to meet a 33% RPS target. Recently approved legislation raises that state's renewable portfolio target to 40% by 2024 and 50% by 2030,[1] in addition to customer-side renewable resources such as rooftop solar. These developments may provide increasing opportunities for EIM participants to purchase energy from California in real time at a low cost.

The focus of this analysis is to provide consistent, conservative estimates of operational cost savings to IPC for evaluation of participation in the EIM. The study does not quantify potential benefits from improved dispatch in the hour-

[1] See California Legislature, 2015:
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

ahead (HA) market or day-ahead (DA) market, which may develop over time as information produced by the EIM informs more efficient DA and HA trading. The study also does not quantify any potential reliability benefits from EIM participation, which are difficult to quantify but may be substantial if participation ultimately assists participants in avoiding a major outage. The study does not quantify potential cost impact on generator maintenance cost as a result of reduced ramping of thermal units. The study does not compare the savings to the incremental costs of joining an EIM. Finally, the study does not estimate savings to IPC or other EIM participants arising from flexibility reserve reductions due to load and variable resource diversity across the footprint.

EIM market discussion

The EIM is a balancing energy market that optimizes generator dispatch within and between Balancing Authority Areas (BAAs) every 15 and 5 minutes.[2] The EIM can create real-time dispatch cost savings for EIM participants by: (1) using software tools to identify sub-hourly transactions that produce an optimized dispatch and minimize production costs, while respecting reliability limits; (2) bringing this optimized dispatch down to a 5-minute interval level; and (3) incorporating optimized real-time unit commitment of quick-start generation.

Additionally, by allowing BAs to pool load and generation resources on a sub-hourly basis, the EIM can enable participants to reduce the number of units they individually need to commit to provide flexibility reserves within the hour. In

[2] For more information regarding the EIM, see https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx.

December 2011, the CAISO implemented a flexible ramping constraint in the five-minute market optimization to maintain sufficient upward flexibility in the system within the hour.[3] Each generator chosen to resolve a constraint is compensated at the marginal generator unit's shadow price, which reflects the opportunity cost for production. The CAISO's calculation of flexible ramping constraints for EIM participants is adjusted downward to reflect diversity of net loads for all participants, subject to transmission constraints. The CAISO determines flexible ramp constraint requirements for each EIM participant based on the aggregate load, wind, and solar resource forecasts and expected variability. By establishing the requirements based on the aggregate load and resource profiles, the benefits of diversity can be reflected in the EIM flexibility reserve requirements. The flexible ramping constraint in the EIM also compensates resources for their contribution to meeting the flexibility constraint. While pooling of flex reserves can reduce variable dispatch and generator commitment costs over time as operators accumulate greater experience with the EIM, participation in the EIM does not reduce the physical generation capacity that a BA needs to serve peak loads and provide system flexibility. Long-term capacity decisions are beyond the scope of this report and are more appropriately examined using other analytical approaches and modeling tools.

[3] See CAISO, 2014: Flexible Ramping Constraint Penalty Price In the Fifteen Minute Market. Available at: http://www.caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf. The CAISO is in the process of introducing a flexible ramping product, which would allow economic bids to be submitted to procure upward and downward ramping capability. https://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

Modeling Approach

This study analyzes the impact of IPC participation in the EIM using the PLEXOS production cost modeling software to simulate sub-hourly operations in the Western Interconnection for the year 2020. Energy Exemplar provided technical support to this study and implemented the sub-hourly production simulation runs in PLEXOS. Savings were identified as *sub-hourly dispatch benefits*, which realize the efficiency of optimized combined 15- and 5-minute dispatch and real-time unit commitment between IPC and the current EIM footprint.

As a starting point, this study used the PLEXOS database developed by Pacific Northwest National Laboratory (PNNL) for the Western Electricity Coordinating Council's (WECC) Variable Generation Subcommittee (VGS) study from 2012-13[4] and revised as part of the NWPP Phase 1 EIM study from 2013.[5] Similar to those two studies, this analysis used a three-stage simulation process, including DA, HA, and real-time simulations stages to represent the different time horizons of actual power system operations. The DA and HA stages are simulated on an hourly basis.

The initial dataset used for this study is the database used in E3's *PGE EIM Comparative Study: Economic Analysis Report*[6], which updated the database

[4] See WECC, 2013, Balancing Authority Cooperation Concepts to Reduce Variable Generation Integration Costs in the Western Interconnection: Intra-Hour Scheduling. Available at **http://energyexemplar.com/wp-content/uploads/publications/Balancing%20Authority%20Cooperation%20Concepts%20-%20Intra-Hour%20Scheduling.pdf**.

[5] See Samaan, NA, et al., 2013, Analysis of Benefits of an Energy Imbalance Market in the NWPP. Available at: **http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-22877.pdf**.

[6] See E3, 2015, PGE EIM Comparative Study: Economic Analysis Report. Available at: **http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf**

from E3's 2014 EIM study for Puget Sound Energy with input from PGE along with representatives from several northwestern BAs. The 2014 PSE database applied PSE- and CAISO-specific updates to the database originally developed for the NWPP Phase 1 EIM analysis.

E3 quantified the sub-hourly dispatch savings from IPC's participation in the EIM by (1) running a real-time BAU case that holds energy transfers between non-participating BAs (which include IPC) equal to the scheduled levels from the HA simulation but allowing EIM participants to transact with other participating BAs in the same real-time market, subject to transmission transfer limits; and (2) running EIM cases (starting from the same HA simulation as the BAU case) that each allow IPC to transact power within the hour with other EIM participants. The increased flexibility in the EIM cases produces a reduction in real time production costs for the region, which represents the total societal EIM-wide savings as a result of IPC participation. Benefits are then divided between IPC and the current EIM participants based on the change in their generation cost and their net purchases and sales in real time through the EIM.

Scenario Description

The Base Scenario of this analysis uses gas hub prices from OTC Global Holding Natural Gas Forwards & Futures, which are $3.27/MMBtu on average for 2020 (in 2015 dollars). The Base Scenario also includes renewable resource development to meet current RPS targets and projected renewable buildout for 2020. This includes a 33% RPS for California, a 15% renewable penetration for IPC, and an average 15% renewable share for other Northwest region BAAs not participating in the EIM. We also analyzed alternative scenarios which model a higher renewable penetration in the west: a 40% RPS for California, a 20% renewable share for IPC, and a 20% renewable share for the other Northwest region BAAs not participating in the EIM.

Summary of results

The base scenarios analyzed through this conservative approach resulted in modest positive sub-hourly dispatch cost savings in 2020 for IPC of $4.5 million in the EIM. IPC participation also provides incremental savings to other EIM participants. These savings are largely robust to the additional retirement of regional coal generation or the absence of planned APS and PGE participation in the EIM, with savings to IPC remaining above $4 million in all scenarios. A higher RPS would result in larger benefits for IPC participation, estimated at $5.1 million per year.

1 Introduction

Idaho Power Company (IPC) engaged E3 to analyze the potential economic benefits of IPC's participation in the Western EIM. This study seeks to identify the savings potential of IPC's participation in the Western EIM and includes a parametric sensitivity analysis to test the robustness of savings results. Sensitivity scenarios include early retirement of certain coal plants in the West, altered participation of other BAs in the EIM, and the penetration level of intermittent renewable resources.

1.1 Context for Study

Utilities throughout the WECC have been increasingly interested in exploring a wider range of opportunities for improved coordination between neighboring BAAs. These have included the

+ Western EIM (previously referred to as the CAISO EIM), which allows for a voluntary 5-minute market. The EIM began operating in November 2014 with PacifiCorp and CAISO as initial members. NV Energy began participating in 2015. Puget Sound Energy and Arizona Public Service have announced participation to begin in 2016. Portland General Electric Company has announced participation to begin in 2017.

+ Northwest Power Pool investigation of a SCED for real time sub-hourly transactions, similar to an EIM, as well as other opportunities to promote more active and liquid 15-minute trading in the region.

A number of studies have highlighted the benefits of improved regional coordination, particularly in a context of higher renewable and intermittent resources on the system. These types of resources incur higher variability and forecast error for each BA, and without regional coordination each individual BA would be forced to maintain higher flexibility to combat this increased intermittency. IPC engaged E3 to conduct a comparative study of the impact and potential savings from IPC participation in the EIM. E3, working with Energy Exemplar, analyzed IPC participation using a three-stage zonal production simulation model of the Western Interconnection in PLEXOS. This study was done in close coordination with Energy Exemplar and IPC staff.

1.2 Structure of this Report

The remainder of this report is comprised of the following sections:

+ **Section 2** describes the key study assumptions and methods used in this analysis.
+ **Section 3** presents the results of our analysis of IPC participation in the Western EIM.

2 Study Assumptions and Approach

2.1 Overview of Approach

The Western EIM allows participating Western BAs to voluntarily participate in CAISO's real-time energy market. EIM software dispatches generation across participating BAAs every 15 and 5 minutes to solve imbalances, as well as committing quick-start generation every 15 minutes using security constrained unit commitment (SCUC). An important distinction between the EIM and a Regional Transmission Organization is that in the EIM each participating BA remains responsible for meeting its own operating reserve and planning reserve requirements, and the EIM does not replace participating BAs' existing operational practices for unit commitment and scheduling in advance of real-time.

This study quantifies the benefit of sub-hourly dispatch capability using a three-stage simulation process in PLEXOS consistent with the approach developed for the WECC Variable Generation Subcommittee (VGS) and refined in PNNL's Phase 1 Report for the NWPP MC Initiative. This methodology is described in detail in Section 2.4 below.

This study is designed to measure one principal type of benefits: **sub-hourly dispatch benefits**. Today, each BA in the Western Interconnection outside of the EIM typically dispatches its own internal generating resources to meet imbalances within the hour, while holding real-time exchange with neighboring BAs fixed to the hour-ahead schedule. The EIM can net energy imbalance across participating BAs and economically dispatch generating resources across the entire EIM footprint to manage the imbalance, resulting in operational cost savings. IPC's participation in an EIM enables incremental dispatch efficiency improvements relative to an EIM without IPC.

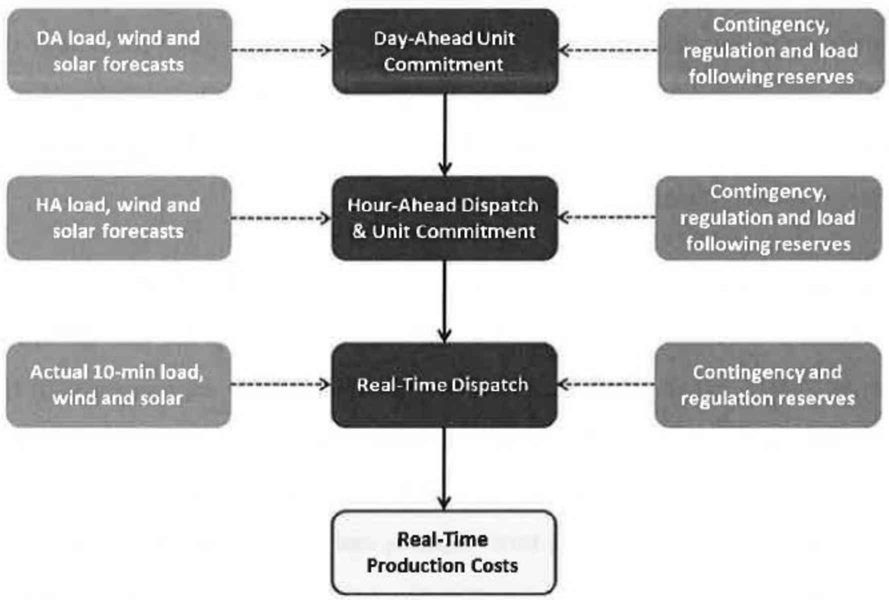
This study does not quantify savings associated with flexibility reserve reductions. Pooling flex reserves can reduce variable dispatch and generator commit costs, especially as operators accumulate greater experience with the EIM. However, each BA still needs to serve peak loads and provide system flexibility; thus, participation in the EIM does not reduce the physical generation capacity that a BA needs. Long-term capacity decisions are beyond the scope of this report and are more appropriately examined using other analytical approaches and modeling tools.

2.2 Sub-hourly Dispatch Benefits Methodology

2.2.1 PRODUCTION COST MODELING

This study used PLEXOS, a sub-hourly production cost model, to estimate sub-hourly dispatch benefits in 2020. PLEXOS, like other production cost models, simulates bulk power system operations by minimizing the variable cost of operating the system subject to a number of constraints. PLEXOS includes a three-stage sequential simulation process to model DA, HA, and real-time operations, as shown in Figure 1 below.

Figure 1. PLEXOS Three-Stage Sequential Simulation Process



The primary purpose of the DA simulation is to generate daily unit commitment schedules for long-start units, while the HA simulation determines the HA dispatch as well as hourly interchange schedules between BAs. During the real-time simulation, the "actual" load, wind, and solar data are used to generate dispatch, and flexibility reserves are "released" so that the capacity reserved from the HA simulation is allowed to serve real-time imbalances. The DA, HA, and real-time sequential simulation approach allows PLEXOS to differentiate operations for BAs participating or not participating in the EIM. When a BA is not participating in a real-time market, then: (a) interchange is unconstrained during the DA and HA simulations; and (b) during the real-time simulation, the HA interchange schedule is locked down, resulting in the BA managing its imbalances with its own generation.

In contrast, during the real-time simulation, BAs participating in the EIM can re-dispatch generation and exchange power with the rest of the EIM footprint during each of the 10-minute intervals, subject to transmission transfer limitations, which are discussed in Section 2.3.2 below.

While the Western EIM operates down to a 5-minute level in practice, the most validated sub-hourly WECC dataset available for this analysis includes 10-minute intervals. Using the 10-minute intervals is a practical but conservative compromise of modeling 15-minute optimization with higher EIM transfer capability and modeling 5-minute optimization with potentially more limited EIM transfer capability across paths limited by dynamic transfer limitations across the California-Oregon Intertie (COI) and BPA network. In the final stage, the RT simulation for this study is run with 10-minute intervals, using actual wind, load, and solar output for each interval. While actual EIM operations are on a 5-minute basis, a complete and validated PLEXOS dataset for 5-minute simulation was not available at the time of this study. This study's use of 10-minute time step in the real-time stage (to make use of the WECC VGS dataset) produces EIM benefits results that we expect may be conservatively low, as the 10-minute time step reduces the amount of variation within the hour to a small extent, slightly moderating the need for operational flexibility that an EIM could provide. Overall, however, we expect the 10-minute time step to capture the majority of the real-time dispatch efficiency savings.

2.2.2 BAU SIMULATION

In the BAU case, IPC does not participate in the EIM, and must resolve its real-time imbalances with internal generation only. IPC's real-time import and exports are held fixed to the hour-ahead schedule.

Real-time sub-hourly interchanges are simulated among BAAs that are modeled as existing participants in the Western EIM, reflecting the operational efficiencies realized by the EIM before including IPC participation. In other words, the Western EIM is assumed to be fully operating without IPC's participation. As a result, savings and efficiencies associated with sub hourly dispatch for each alternative are included in the system cost. These costs serve as the "control" case to compare against the cases with IPC participation.

The BAU case includes operations of a "current EIM" consisting of the seven BAAs that were participating or had announced plans to participate in the EIM at the start of this study. The BAAs modeled as current participants in the EIM for the BAU Case are listed in the table below.

Table 3: BAA Participants in EIM in BAU Case

Current EIM participants for BAU Case
CAISO
PacifiCorp East (PACE)
PacifiCorp West (PACW)
NV Energy (NVE)
Puget Sound Energy (PSE)
Arizona Public Service (APS)
Portland General Electric (PGE)

2.2.3 WESTERN EIM SIMULATIONS

The EIM cases simulate real-time dispatch with IPC participating in the Western EIM. In each of these cases, intra-hour interchange between IPC and existing EIM participants is allowed up to the assumed transmission transfer limits.

2.3 Key Modeling Assumptions

Three key modeling assumptions are important for understanding the results of this study: (1) sub-hourly dispatch; (2) real-time transmission capability; and (3) hurdle rates.

2.3.1 SUB-HOURLY DISPATCH

In existing operational practice, BAs in the Western Interconnection exchange energy primarily on an hourly basis using hourly or multi-hour schedules, or standardized energy products which include On-Peak, Off-Peak, and Flat energy blocks. These products require long lead times between scheduling the transaction and actual dispatch.[7] Within the hour, each BA resolves imbalances by dispatching generating resources inside its BAA, without the assistance of other BAs. By contrast, the EIM optimizes dispatch of available generating resources in real time across all of the participating BAAs using 15-minute unit commitment and 5-minute dispatch. These sub-hourly processes increase the efficiency of resolving imbalances.

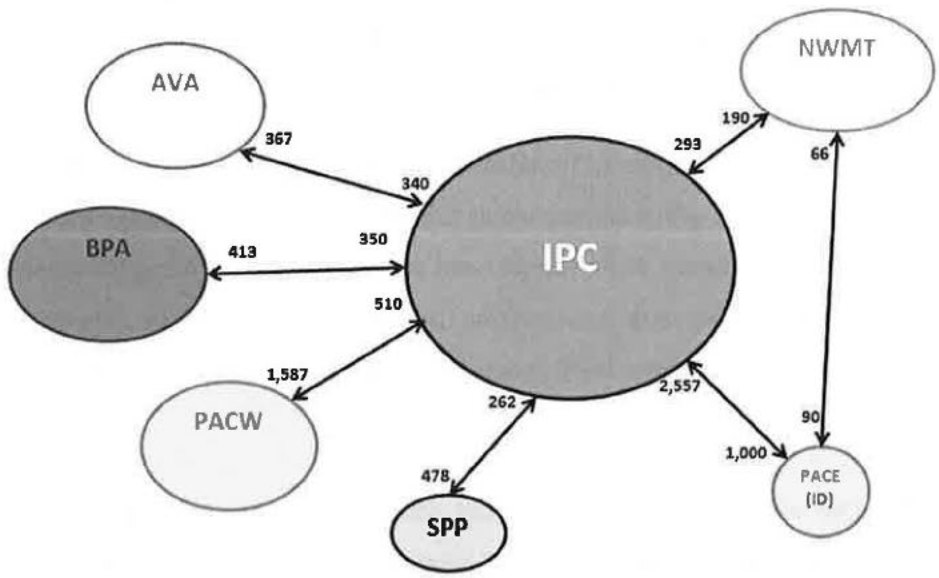
2.3.2 REAL-TIME TRANSMISSION TRANSFER CAPABILITY

Previous studies have indicated that transmission can constrain EIM benefits by limiting the amount of power that can be transferred in real time between participants. This study's transmission topology was built on that of E3's PGE EIM study from 2015 and was updated with the help of IPC transmission experts.

IPC's BAA has direct connections with six other BAAs: AVA, BPA, PACW, PACE, NVE, and NWMT. IPC has significant transfer capability with both PACE and PACW. In the BAU Scenario (without IPC participating) PACE and PACW were assumed to have only 200 MW of east to west dynamic capability between them available for incremental EIM transfers not scheduled in the hour ahead. A zonal depiction of IPC's transmission interconnections is shown in Figure 2.

[7] The Western EIM and AESO are the exceptions.

Figure 2. Real-time Transfer Capabilities with IPC



2.3.3 HURDLE RATES

Within the Western Interconnection's bilateral markets, there are a number of impediments to efficient trade of energy across BAA boundaries. These include:

+ The need, in many cases, for market participants to pay for the fixed costs of the existing transmission system by redirecting or acquiring additional point-to-point transmission service in order to schedule transactions from one BAA to another;
+ The current tariff practice of requiring short-term transactions to provide real power losses for each transmission provider system that is utilized, in some cases resulting in multiple or "pancaked" loss requirements that are added to the fixed costs described above; and

+ Inefficiencies related to having illiquid bulk power and transmission service markets and imperfect information, such as DA block trading products, minimum transaction quantities of 25 MW, and the bilateral nature of transaction origination and clearing.

These real-world barriers to trade are reflected in production cost simulations as "hurdle rates", which are applied as $/MWh price adders to energy transfers on interfaces between BAAs. Hurdle rates are applied in the DA and HA cases to inhibit power flow over transmission paths that cross BAA boundaries, to represent these inherent inefficiencies and reduce economic energy exchange between BAAs.

The EIM eliminates the barriers listed above during real-time operations by performing security-constrained economic dispatch across the entire EIM footprint, allowing more efficient (i.e., lower cost) dispatch. Our production simulations in PLEXOS capture this effect by removing hurdle rates in real time. Intra-hour exchanges among participants in the EIM are allowed during the real-time simulation cases. The simulation does not allow incremental intra-hour exchanges (beyond the HA schedule) between BAAs that are non-participants in an EIM. The absence of hurdle rates in real time in this analysis is consistent with the FERC-approved CAISO tariff amendment associated with the EIM.

In the DA and HA simulations, hurdle rates are maintained between all BAAs, including between EIM participants. We believe this is a conservative assumption regarding the expected adaptation of DA and HA markets based on information identified by the EIM. In reality, we expect that BAs may adjust their DA and HA scheduled transactions more efficiently over time based on learning the dynamics of the real-time market results. This learning does not imply a shift away from DA and HA scheduling, but rather a more efficient and better informed selection of scheduling levels for any hour based on learning from real-time market participation. To the extent it can be realized, this opportunity for learning and improved DA and HA efficiency is a non-quantified benefit that would be additional to those quantified in this report.

In addition to the hurdle rates described above, charges for CO_2 import fees related to California Assembly Bill (AB) 32 are still applied to energy transfers from BAs outside of California to California BAs. These charges are applied in all cases, including real-time.

For interties among the current EIM participants, hurdle rates were applied to the DA and HA cases, but removed during the real-time case runs for both the BAU and EIM cases.

2.3.4 FLEXIBILITY RESERVE REQUIREMENTS

By pooling load and resource variability across space and time, total variability of the combined net load for participants in the EIM footprint can be reduced, decreasing the amount of flexibility reserves required to ensure reliable operations. This reduces operating costs by:

- requiring fewer thermal generators to be inefficiently committed and operated, and
- decreasing flex reserve requirements placed on hydro resources, enabling them to more efficiently generate energy at times most valuable to their systems.

Units that provide regulating reserves must respond faster than the EIM's 5-minute dispatch interval, so EIM participants are assumed here to receive no regulating reserve diversity savings as a result of participation in the EIM.

While there is currently no uniformly defined requirement for BAs to carry flexibility reserves, all BAs must maintain Area Control Error (ACE) within acceptable NERC-defined limits, which necessitates that BAs hold reserves on generators to respond to within-hour changes in load and variable resource output. These reserve needs will grow under higher renewable penetration scenarios.

Additionally, in December 2014, the CAISO implemented a flexible ramping constraint in the five-minute market optimization to maintain sufficient upward flexibility in the system within the hour.[8] Generators that are chosen to resolve a constraint are compensated at the generation shadow price, which reflects the marginal unit's opportunity cost. Furthermore, the CAISO is in the process of introducing a flexible ramping product, which would allow economic bids to be submitted to procure upward and downward ramping capability.

The CAISO's calculation of flexible ramping constraints for EIM participants is adjusted to reflect diversity of net loads for all participants, subject to transmission constraints. The CAISO determines flexible ramp constraint

[8] See CAISO, 2014, Flexible Ramping Constraint Penalty Price In the Fifteen Minute Market. Available at: http://www.caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf. See also CAISO , 2015, Flexible Ramping Products Revised Draft Final Proposal. Available at: https://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

requirements for the CAISO and each EIM participant based on the aggregate load, wind, and solar resource forecasts and expected variability. By establishing the requirements based on the aggregate load and resource profiles, the benefits of diversity can be reflected in the EIM flexibility reserve requirements. The flexible ramping constraint in the EIM also compensates resources for their contribution to meeting the flexibility constraint.

In the simulations run for this study, flexibility reserves were **not** adjusted to reflect net load diversity in any scenario (BAU and EIM case). This means that the benefits found in this study do not include benefits arising from reductions in flexibility reserves upon joining the EIM. In a previous study, E3 estimated that PGE would receive $0.8 million in *additional* savings due to reduced flexibility reserves from joining the Western EIM.

2.4 Detailed Scenario Assumptions

2.4.1 INPUT DATA

The initial dataset used for this study is the database used in E3's *PGE EIM Comparative Study: Economic Analysis Report*[9], which updated the database from E3's 2014 EIM study for Puget Sound Energy with input from PGE along with representatives from several northwestern BAs. The 2014 PSE database applied PSE- and CAISO-specific updates to the database originally developed for the NWPP Phase 1 EIM analysis.

[9] See E3, 2015, PGE EIM Comparative Study: Economic Analysis Report. Available at: http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf.

This study for IPC further refined the study database used in the PGE EIM analysis. These refinements are described below in more detail. Utilizing this database allowed this study to reflect the best available information compiled to represent BAAs in the Northwest.

This study made the following key updates to the case:

+ **Topology updates**. The 2015 PGE EIM study was used as a starting point for topology data. Major changes include removing a transmission link from SCL to IPC zones because it is a link to SCL-owned hydro generator at Lucky Peak, not the SCL balancing authority area. Additionally, E3 updated the line rating for the link between Northwestern and IPC to reflect the latest WECC path ratings.
+ **Gas prices**. Monthly 2020 hub prices came from OTC Global Holding Natural Gas Forwards & Futures (provided by SNL) for selected hubs in the West region.[10] As in the PGE EIM study, these data were translated from hub prices to BA- or plant-specific burner tip prices using the mapping of pipelines, variable transport fees, and other adjustments outlined in the NWPP Phase 1 assessment.
+ **Hydro optimization window**. In practice, IPC plans its dispatch of flexible hydro units up to a week in advance to optimize the value of its reservoirs. This flexibility of hydro generation is prominent in the Northwest. Yet modeling hydro as such in PLEXOS runs the risk of unrealistically optimizing hydro dispatch with perfect foresight over a very long time horizon, without reflection of forecast error in identifying when the hydro will most be needed. Therefore, to balance dispatchable hydro units and maintain flexibility, while preventing

[10] Obtained from SNL Financial LC on October 15, 2015

perfect foresight, dispatchable hydro units for this study are optimized with a 24-hour optimization window. In this study, hydro modeling is handled through a series of interactions between simulation stages: monthly hydro energy budgets, which are database inputs, are allocated to each day using PLEXOS's monthly MT simulation based on anticipated load, wind, and solar across the month. Then, the DA and HA simulation stage first optimizes the hydro for each hour based on a DA and HA forecast of hourly load, wind and solar, constrained by the daily generation budget. The RT simulation is permitted to update the hourly hydro schedule across the day to respond to real-time needs within each of the six 10-minute sub-hourly intervals each hour but must maintain the same daily hydro energy total.

+ **Renewable generation updates in California**. Consistent with the PGE EIM study, this analysis has also updated the CAISO renewable resource mix to reflect a higher expected share of solar PV in the 2020 renewable resource portfolio and lower share of wind resources, based on current and planned additions for meeting the state's 33% RPS target by 2020. The resource mix was also adjusted to include additional rooftop PV solar in the CAISO, which was not reflected in the original TEPPC model.

+ **Generation updates in the Northwest**. In order to collect and verify generator data for the PGE EIM study, PGE arranged discussions with experts from several northwestern BAs, including IPC. The data collected from these sessions were integrated in the PGE study database. For this study, IPC reviewed and largely maintained this data, making minor changes to its generator fleet. In the early coal retirement scenario the following units were retired as well: Valmy1, Valmy2, RdGrdnr4, Navajo1, SanJuan2, SanJuan3.

2.4.2 DISPATCH SAVINGS SCENARIOS

The dispatch savings were evaluated under 4 scenarios with different assumptions regarding the current participants in the EIM, the retirement dates of coal plants throughout the west, and the buildout of renewable resources by 2020. The scenarios were developed based on input from IPC staff to highlight changes that IPC believed both plausible to occur and also valuable to explore to test the robustness of EIM savings. Table 4 summarizes the assumptions used for each scenario modeled for calculating sub-hourly benefits.

Because IPC is interested in the benefits of joining the Western EIM[11], this study defines a base scenario that represents a plausible trajectory for the West's operating environment in which IPC joins the Western EIM. This base scenario is subjected to three sensitivities: (1) APS and PGE are assumed to not have joined the EIM by 2020 as planned; (2) Certain coal plants in the West are modeled to retire earlier than planned in the base case; and (3) significant renewable generation is added in California and throughout the West.

[11] In all scenarios but one, CAISO, PAC, NVE, PSE, APS, and PGE are assumed to be already participating in the Western EIM in order to provide the most accurate baseline scenario, given the information available over the course of this study. A single sensitivity scenario models APS and PGE as not having joined the EIM by 2020.

Table 4. Overview of EIM Scenario Assumptions

	Renewable Energy Target (%)*				
Scenario	IPC	CAISO	Other NW BAAs	Coal Capacity in WECC (GW)	BAAs in EIM Case
1. Base	15%	33%	15%	35.0	CAISO, PACW, PACE, NVE, PSE, APS, PGE, IPC
2. No APS or PGE in EIM	15%	33%	15%	35.0	CAISO, PACW, PACE, NVE, PSE, IPC
3. Early Coal Retirements	15%	33%	15%	31.3	CAISO, PACW, PACE, NVE, PSE, APS, PGE, IPC
4. High RPS	20%	40%	20%	35.0	CAISO, PACW, PACE, NVE, PSE, APS, PGE, IPC

*PGE BAA includes non-PGE customers, resulting in a smaller renewable energy share of BAA load than RPS target; CAISO RPS includes renewable energy from out of state imports, does not reflect behind the meter PV generation.

Table 5. Renewable Capacity Added in High RPS Scenario (MW)

Region	Zone	Wind	Solar PV	Geothermal
FAR EAST	IPC		128	
MAGIC	IPC		132	
TREAS	IPC		112	
PG&E_VLY	CAISO	2,489	1,973	
SCE	CAISO	514	1,724	491
SDGE	CAISO	102		
AVA	NW	774		
BPA	NW	1,737	135	
PGE	NW	484		
SMUD	NW	498	616	
TIDC	NW		84	

2.5 Methodology for Attributing Benefits to IPC and Other Participants

To evaluate the benefits yielded by an EIM, we calculated the difference between procurement costs in a business-as-usual case and in an EIM case. There are three components of total procurement costs in our model: hour-ahead net import costs, real-time imbalance costs, and real-time generation costs. First, we define a few terms.

+ Hour-ahead net imports: the hourly difference between imports and exports.

- Locational marginal price (LMP): a given BA's generation shadow price in a certain time period (the cost of generating an additional MWh of electricity).[12]
- Real-time imbalance: the within-hour energy imbalance found in the EIM cases, where trading occurs at 10-minute intervals.
- Average LMP: the imbalance-weighted average of all EIM BAs' LMPs.

Hour-ahead net import costs are calculated as the product of hour-ahead net imports and the locational marginal price, and then summed over all hours in the year. Real-time imbalance cost to a given BA is a 10-minute interval's imbalance multiplied by that interval's average LMP, summed over all 10-minute intervals in the year. Real-time generation costs include the variable costs of energy production modeled in PLEXOS – fuel prices (updated by E3 based on OTC Global Holding Natural Gas Forwards & Futures data provided by SNL), and variable operation and maintenance and unit startup costs (based on the costs characteristics for units in the TEPPC database, but not directly modified for this study).

Total savings associated with an EIM are the difference between the sum of hour-ahead net import costs, real-time imbalance costs, and real-time generation costs in the business-as-usual case and the EIM case. In all scenarios, the hour-ahead simulation is identical for the business-as-usual and the EIM cases, meaning the hour-ahead net import costs can be ignored in the

[12] The minimum LMP used for calculating benefits was set to -\$100/MWh, which is the model's penalty price for overgeneration. In overgeneration conditions, renewable resources may be curtailed but also could require replacement costs for renewable energy to fulfill RPS goals in some jurisdictions.

calculation. Table 6 provides an example of benefits parsing that highlights the methodology discussed in this section.

Table 6. Benefits Parsing in the Base Scenario, IPC in Western EIM

Costs (2015$ million)*	Business-as-Usual	Western EIM	EIM Savings vs. BAU
Real-Time Generation and Import Costs	$108.8	$110.1	($1.3)
Real-Time Imbalance Costs (Market Revenues)	($0.1)	($5.9)	$5.8
Total Real-Time Procurement Costs	**$108.7**	**$104.2**	**$4.5**

Note: Individual estimates may not sum to total due to rounding. Positive values in the final column represent cost reductions, or savings in the EIM case relative to the BAU.

3 Results

3.1 Benefits to IPC

Table 7 below presents the simulated annual benefits of IPC participation in the EIM in 2020 under each sensitivity scenario. Each cell in the table represents the incremental benefit to IPC as a result of its participation in the EIM. These savings are each calculated as the reduction in cost compared to the IPC BAU case. Overall, the dispatch cost savings range from $4.1 million in the early coal retirement scenario to $5.1 million in the high RPS scenario. Reduced reserves would provide additional savings in addition to these figures, though reserve reductions were not modeled for this study.

Table 7. Annual Benefits to IPC by Scenario, EIM (2015$ million)

Scenario	Dispatch cost savings to IPC
Base	$4.5
Sensitivity Scenarios	
No APS/PGE in EIM	$4.2
Early Coal Retirement	$4.1
High RPS	$5.1

*Dispatch cost savings for Sensitivity Scenarios are shown as alternatives to the Base case, not cumulative additions. Reserves savings were not modeled.

EIM base scenario savings to IPC were $4.5 million with a decrease in annual real-time procurement costs (real-time generator production cost plus real time imbalance cost of purchases and revenue from sales) from $108.7 million in the BAU case to $104.2 million in the EIM case (a reduction of more than 4%). Section 3.3 goes into more detail for each sensitivity scenario.

3.2 Incremental Benefits to Current EIM Participants

Table 8 below presents the simulated incremental benefits resulting from IPC's EIM participation to the current participants in the EIM. IPC's EIM participation is expected to create $2.2 to $3.1 million in yearly savings to the current EIM participants across all scenarios.

Table 8. Annual Benefits to Current EIM Participants by Scenario (2015$ million)

Scenario	Incremental savings to Existing EIM Participants
Base	$2.9
Sensitivity Scenarios	
No APS/PGE in EIM	$2.2
Early Coal Retirement	$3.0
High RPS	$3.1

*Dispatch cost savings for Sensitivity Scenarios are shown as alternatives to the Base case, not cumulative additions. Reserves savings were not modeled.

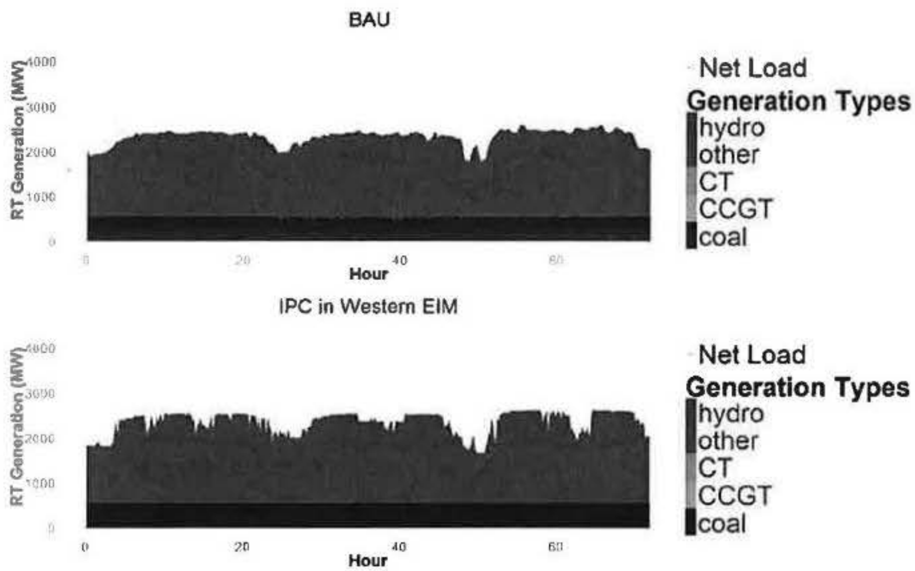
3.3 EIM Results Discussion

3.3.1 BASE SCENARIO

The base scenario brings $4.5 million of savings to IPC, as well as $2.9 million to the existing EIM participants. Various factors underlie EIM participation benefits in the scenarios modeled. In all scenarios, EIM participation enables IPC to export and import with other EIM participants in real time to respond to intra-hour imbalances. As illustrated in Table 6, IPC's real-time generation costs increase in the EIM, while its imbalance costs decrease by a larger amount. This is because, in the EIM, IPC can export its hydro generation extremely flexibly at 5-minute intervals, ramping the units up when LMPs are high and down when prices are low. A second benefit of EIM participation is smoother operation of thermal units; the real-time flexibility of the EIM prevents thermal generators from having to respond to within-hour imbalances (for the most part), decreasing ramping. This flexibility also allows IPC to avoid starting and running its CT generators at times.

The following chart illustrates all the benefits described above, displaying IPC's dispatchable generation in real time over a three-day period in the spring. In the EIM dispatch chart, hydro output is highly variable at the 10-minute level, in striking contrast to the smooth hydro output seen in the BAU case. Thermal generation is perfectly constant in the EIM case, whereas ramping is required in the BAU case. Furthermore, CT units are not used at all in the EIM case, whereas CT units are started and turned off at least four times in the BAU case.

Figure 3. IPC Real-Time Dispatchable Generation, Western EIM, April 28 – May 1



3.3.2 ALTERNATIVE SCENARIOS

Modeling APS and PGE as not in the EIM slightly reduces the size of the total EIM market and has a small downward impact on IPC savings relative to the base case, to $4.2 million.

The scenario with additional retirement of regional coal generators produces savings $0.4 million lower than the savings to IPC in the base scenario ($4.1 million in the early coal retirement case - $4.5 million in the base case). This difference is less than 10% of total savings, and is thus also fairly insignificant, indicating that model results for identified IPC savings are robust to participation and coal resource retirement.

The high RPS scenario brings $5.1 million of savings for IPC, which is $0.6 million higher than the savings in the base scenario. As expected, a higher renewable generation buildout increased savings to IPC, as the EIM allows resources from a wider area to address real-time variability in net load, and creates increased revenue opportunities for IPC's flexible hydro generation in the real-time market.

Docket No. UE 323
Exhibit PAC/1000
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of Dana M. Ralston

August 2017

SURREBUTTAL TESTIMONY OF DANA M. RALSTON

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ATTACHED EXHIBIT

Q. Are you the same Dana M. Ralston who previously submitted direct and reply testimony in this Transition Adjustment Mechanism (TAM) 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 testimony addresses three issues. First, I respond to the rebuttal and cross-answering testimony filed by Dr. Lance Kaufman on behalf of Staff of the Public Utility Commission of Oregon (Staff) on August 2, 2017, in which he continues to propose an adjustment to the amount of liquidated damages at the Cholla plant.

Second, I respond to the rebuttal testimony of Sierra Club witness Dr. Thomas Vitolo. While Sierra Club has now withdrawn its $2.4 million adjustment to coal costs at the Naughton plant, it still incorrectly claims that the company dispatched the plant non-economically in 2015 and 2016. I also respond to Sierra Club's general criticisms of PacifiCorp's coal plant modeling and dispatch.

Third, I provide an update on the Jim Bridger third-party coal contract negotiation status.

Q. Please summarize your surrebuttal testimony.

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

- PacifiCorp's approach to modeling liquidated damages under the Cholla coal supply agreement (CSA) ties directly to the terms of the Cholla CSA and the company's preliminary nomination for 2018 coal purchases under the CSA. Staff's adjustment is based on the incorrect premise that liquidated damages should be calculated on the higher volume of coal consumption at the Cholla plant. This is inconsistent with the CSA, and discounts the company's reasonable use of its current coal inventory for a portion of the Cholla plant's coal supply in 2018.

- PacifiCorp was prudent in managing coal supply to its Naughton plant, including purchasing above the minimum take levels in the Naughton CSA. My analysis demonstrates that PacifiCorp's dispatch of the Naughton plant was more advantageous to customers than Sierra Club's alternatives.
- Sierra Club's recommendation that the Public Utility Commission of Oregon (Commission) preclude PacifiCorp from entering into any future CSAs is unsupported and would increase costs and risks to customers.

STAFF'S COAL PRICE ADJUSTMENT

Q. Please describe Staff's position concerning the liquidated damages calculation under the Cholla CSA in the 2018 TAM.

A. Staff calculates the liquidated damages associated with the Cholla CSA based upon coal consumption, not coal purchases, disallowing any reliance on coal inventories to supply the Cholla plant in 2018. Staff re-calculates the liquidated damages to be [redacted][1] and recommends an adjustment that reduces total NPC by [redacted] total-company, or [redacted] on an Oregon-allocated basis.

[1] Staff/500, Kaufman/47.

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

A. In the reply update, PacifiCorp forecasts liquidated damages of [redacted], based on [redacted] tons of projected coal purchases in 2018. The liquidated damages provision of the current Cholla CSA provides that if PacifiCorp purchases between [redacted] and [redacted] tons of coal in a calendar year, liquidated damages of [redacted] per ton are charged for each shortfall ton. Liquidated damages of [redacted] per ton are charged for each ton below [redacted] tons of coal in a calendar year.[2]

In the reply update, PacifiCorp forecasts that [redacted] tons of coal will be burned at the Cholla plant in 2018, meaning that the company will draw [redacted] from the plant's coal inventory, rather than purchasing the entire [redacted].

Q. Please describe why PacifiCorp will use its current coal inventory for a portion of the Cholla plant's coal supply in 2018.

A. The January 2017 beginning stockpile inventory balance of [redacted] tons was significantly over the target level of [redacted] tons and needed to be reduced. By June 2017, the stockpile balance was down to [redacted] tons and the forecast for December is approximately [redacted] tons. PacifiCorp expects to further reduce the stockpile balance by approximately [redacted] tons during 2018 unless market conditions change. The company's gradual reduction of its stockpile at the Cholla plant to target levels is fully consistent with prudent plant operating practices, and reduces plant operating costs and risks.

Q. What is Staff's first argument for reducing liquidated damages?

A. Staff claims that PacifiCorp's actions in 2016 caused the Cholla plant's stockpile to

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[2] The second amendment to the Cholla CSA was executed in February 2017. Before execution of the second amendment, all shortfall tons were subject to the [redacted] per ton liquidated damages rate.

grow to its current size. Based on this claim, Staff reasons that the liquidated damages that will be incurred in 2018 to drawdown the stockpile level are attributable to 2016, not 2018. Therefore, PacifiCorp should have recovered the liquidated damages that will be paid in 2018 in 2016.[3]

Q. Does this argument have merit?

A. No. The liquidated damages forecast for 2018 are triggered by the Company's coal burns and inventory levels in 2018, not in 2016. Staff essentially argues that in the 2016 TAM, PacifiCorp should have anticipated the possibility of incurring liquidated damages in 2018 and built those expected costs into the 2016 TAM forecast. But no party would have agreed to increase coal prices in 2016 based on speculation that the company might incur liquidated damages in the future. Staff's argument that liquidated damages must be attributed to prior periods would, as a practical matter, unfairly preclude PacifiCorp from ever recovering liquidated damages because the cause of the liquidated damages could nearly always be attributed to a prior year.

Q. Is Staff's position regarding liquidated damages consistent with the treatment of CSA carryover provisions in previous cases?

A. No. PacifiCorp has used carryover provisions in its CSAs to benefit customers in previous cases. For example, in docket UE 207, PacifiCorp's coal costs included lower-priced carryover coal from the previous year, which reduced a coal price increase from 50 percent to 34 percent.[4] In that case, Staff argued explicitly that

[3] Staff/500, Kaufman/48.
[4] *See, e.g.*, Docket No. UE 207, PPL/200, Lasich/4 (describing an expiring Black Butte contract: "The new agreement replaces an existing agreement that expires in December 2009. The 2010 price under the new contract is approximately 34 percent higher than the 2008 coal price. This 2010 pricing takes into account lower priced carryover tonnage from the prior contract. Excluding the carryover tonnage, the new contract price increase is over 50 percent.").

customers must receive the benefits of carryover coal because that was the actual cost PacifiCorp was paying for coal.[5] Under Staff's rationale here, however, customers should not benefit from carryover coal because the operational decisions that resulted in the availability of carryover tons occurred in a prior period.

Q. Please describe the different challenges that can occur at a coal plant that result in coal consumed being different than coal purchased.

A. Variances between consumed coal and purchased coal can arise due to economic dispatch decisions, unscheduled outages (tube leaks, etc.), or timing differences in agreed-upon delivery schedules. Coal supplier variances also arise due to mine production issues, coal quality blending issues, and mining equipment repairs or breakdowns. Coal transport variances can arise from truck or train equipment issues, staffing issues, track repair, and scheduling issues. Plant stockpiles serve as the buffer and protection to all of these challenges and also serve as a valuable tool to manage liquidated damages.

Q. Please describe the conditions at the Cholla plant that led to low consumption levels during 2016 and high stockpiles at the end of the year.

A. The market conditions that existed in 2016 could not reasonably be anticipated when PacifiCorp made its nominations in [redacted] of 2015 for 2016 coal deliveries to the Cholla plant.[6] The beginning stockpile balance in January 2016 was [redacted] tons and by the end of December 2016, the stockpile balance had increased to [redacted] tons. The inventory level increased in 2016 because low power market prices

[5] Docket No. UE 207, Staff/400, Dougherty/21.
[6] Before execution of the second amendment to the Cholla CSA in February 2017, the CSA only required one nomination in [redacted].

displaced or reduced generation at the Cholla plant, which resulted in minimal coal being consumed from February to June, but also impacted the balance of the year. The initial stockpile level in January 2016 was below the target range and therefore PacifiCorp was able to use the plant stockpile to absorb some coal deliveries and avoid liquidated damages.

Q. Was PacifiCorp's use of its coal stockpile in 2016 to manage unexpected changes in coal burns at the Cholla plant consistent with Staff's position in the 2017 TAM?

A. Yes. In response to market conditions, Staff's testimony in the 2017 TAM (filed in the summer of 2016) urged PacifiCorp to rely on its stockpiles to avoid liquidated damages to the extent possible.[7]

Q. Were there other considerations that led to the increase of the Cholla plant's stockpile in 2016?

A. Yes. Peabody Energy (Peabody) filed bankruptcy in April 2016, and PacifiCorp, along with the plant co-owner Arizona Public Service, initiated litigation to terminate the CSA. Many months of uncertainty surrounded the outcome of the pending litigation. As such, PacifiCorp decided to purchase coal in 2016 under both the CSA and two additional short-term interim agreements with Peabody, which provided volume credit against any higher liquidated damages and increased the coal inventory in case the litigation produced a sudden change in coal suppliers. Peabody's bankruptcy was not reasonably foreseeable when PacifiCorp nominated its 2016 coal deliveries to the Cholla plant in [redacted] of 2015.

[7] Docket No. UE 307, Staff/400, Kaufman/42 ("Staff proposes that PacifiCorp allow 2017 year-end inventory levels to reach maximum capacity prior to artificially modifying dispatch tier GRID prices.").

Q. Staff's second argument is that PacifiCorp does not need to drawdown the inventory levels at the Cholla plant in 2017.[8] Does this argument have merit?

A. No. Staff's only support for this claim is the fact that the average inventory in the initial 2017 TAM filing was [redacted] tons and the actual average inventory from 2013 to 2017 was [redacted].[9] Staff reasons that "if this level of inventory was indeed not appropriate PacifiCorp should not have allowed the pile to grow so large or stay that large for over five years."[10] Staff, however, does not recognize that the projected December stockpile amount influences the volume that is nominated for the following year; thus, the average annual inventory is not the appropriate metric for determining how much coal to purchase. In the 2018 TAM reply update, PacifiCorp anticipates having [redacted] tons as of December 2017, which is 18 percent higher than December 2013, 59 percent higher than December 2014, and 135 percent higher than December 2015.[11] Based on the appropriate metric, maintaining the December 2017 inventory levels into 2018 is unreasonable.

Q. Are there costs associated with maintaining coal inventories above target levels?

A. Yes. PacifiCorp earns a return on coal inventories, based on target levels established during general rate cases. The Cholla plant's current inventory is above the level used to set Oregon rates—meaning that PacifiCorp is incurring the carrying costs associated with its elevated inventory levels. Staff's adjustment does not take into account the offsetting costs PacifiCorp incurs in maintaining excess coal inventories.

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[8] Staff/500, Kaufman/48-49.
[9] *Id.*
[10] Staff/500, Kaufman/49.
[11] *See* Staff/500, Kaufman/52 (setting forth year-end inventories for 2013 to 2017).

Q. Are there operational risks associated with maintaining coal inventories above target levels?

A. Yes. As noted above, plant stockpiles serve as a buffer and protection in the event of unexpected reductions in generation due to economic dispatch decisions, unscheduled outages or other events. The value to customers of this buffer is diminished when stockpiles exceed target levels.

Q. Are there any other problems that would result from continuing to grow Cholla plant inventories in 2018?

A. Yes. Under PacifiCorp's 2017 Integrated Resource Plan, Cholla Unit 4 is forecast to retire at the end of 2020. Consistent with this forecast, the coal stockpile should be reduced to zero by December 31, 2020. If PacifiCorp does not begin drawing down the stockpile level in 2018, it runs the risk of pushing higher cost liquidated damages into future years or forcing generation at the plant to manage the inventory to align with the potential closure date.

Q. Staff also argues that PacifiCorp's 2018 nomination of [redacted] tons of coal for the Cholla plant is imprudent.[12] How do you respond?

A. Staff's argument is based on incorrect assumptions. Staff claims that between PacifiCorp's initial filing in the 2018 TAM and its 2018 TAM reply update, the forecasted coal burn at the Cholla plant increased and the forecasted inventory decreased. Based on these two claims, Staff argues that PacifiCorp should have increased its nomination to [redacted] tons so that the company would have the flexibility when it made its final nomination to nominate at either its calculated level

[12] Staff/500, Kaufman/49.

or Staff's.[13] But Staff fails to recognize that the maximum volume of coal that PacifiCorp can purchase without Peabody's consent is [redacted] tons. PacifiCorp does have the right to nominate more than [redacted] tons if the consumed coal projections justify the higher nomination. Peabody has the right to decline to deliver anything over [redacted] tons, however, and the consumed forecast does not justify receiving greater than [redacted] tons in 2018.

Q. Please describe the annual coal purchase nomination process for 2018 at the Cholla plant.

A. Annual nominations are determined based upon contractual terms and conditions and are designed to provide the coal supplier with sufficient time to plan for coal deliveries that are then integrated into its comprehensive mine plan. PacifiCorp provided a preliminary nomination to Peabody on [redacted], for the 2018 calendar year coal purchases. PacifiCorp was contractually obligated to provide the preliminary nomination by [redacted]. The final nomination is due by [redacted]. As a general rule, at the time that nominations are required, PacifiCorp uses the most recent coal consumption forecast available for the balance of the current year and the following calendar year. That forecast will continue to change over subsequent months depending on power market prices, market conditions, and other factors. This will naturally create a discrepancy between tons purchased and tons consumed in 2018. At the Cholla plant, the company used the most recent generation forecast developed in [redacted] for the nomination.[14]

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[13] Staff/500, Kaufman/50.

[14] It is worth noting that Staff's reliance on the TAM update schedule to inform the nomination process is improper. PacifiCorp's nominations rely on a forecast of expected conditions in 2018; whereas, the TAM relies on a normalized forecast. Thus, the TAM forecast does not actually determine the nomination levels.

The final nomination can be adjusted up or down by [redacted] of the tonnage provided for in the preliminary nomination. The preliminary nomination of [redacted] tons was designed to give PacifiCorp the ability to flex up to [redacted] tons (the maximum guaranteed volume under the current CSA) or flex down to [redacted] tons for the final nomination. In other words, PacifiCorp's preliminary nomination allowed it the greatest flexibility possible, based on the terms of the CSA and all available information about 2018 coal consumption at the Cholla plant.

Q. Staff claims that PacifiCorp provided no evidence that Peabody would [redacted] tons of coal.[15] How do you respond?

A. [redacted]

Q. Staff argues that PacifiCorp should not recover liquidated damages even if incurring liquidated damages was necessary to avoid maintaining the "coal pile at questionably high levels."[16] How do you respond to this argument?

A. Staff's argument is without merit. If it is prudent for PacifiCorp to draw down its Cholla plant inventory in actual operations, then PacifiCorp should recover the costs to do so in the TAM.

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[15] Staff/500, Kaufman/53.
[16] Staff/500, Kaufman/51.

Q. Staff also presents a hypothetical scenario purporting to show how PacifiCorp could manipulate liquidated damage provisions in its coal contracts to shift costs to customers.[17] How do you respond?

A. Staff's hypothetical assumes that in [redacted] 2015, PacifiCorp knew that its 2016 NPC would be within the Oregon Power Cost Adjustment Mechanism (PCAM) deadbands and therefore chose not to incur liquidated damages because those would not have been recoverable through the PCAM. But PacifiCorp could not have known in [redacted] 2015 that its overall 2016 NPC would fall within the PCAM deadbands. Without this predicate knowledge, there could be no improper manipulation. PacifiCorp does not manage its NPC forecast by taking into account the PCAM deadbands, as Staff implies. PacifiCorp manages NPC to achieve the lowest-cost, least-risk power supply for our customers, while maximizing operational considerations.

Q. Staff claims that PacifiCorp did not disclose certain components of the Cholla CSA.[18] Is this accurate?

A. No. As stated in my direct testimony, PacifiCorp signed an amendment to the Cholla CSA in February 2017 that changed several terms of the original CSA. I explained many of the terms and details of the new amendment in my direct testimony and reply testimony. If Staff had specific concerns, it could have requested review of the current Cholla CSA at any time before filing its rebuttal testimony.[19]

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[17] Staff/500, Kaufman/52.
[18] Staff/500, Kaufman/53.
[19] PacifiCorp did not receive a discovery request from Staff requesting the current Cholla CSA until August 4, 2017, two days after Staff filed its rebuttal testimony.

Q. Staff proposed a workshop and a report analyzing PacifiCorp's "considerations and processes of entering into new long-term contracts."[20] Is PacifiCorp amenable to this proposal?

A. Generally, yes. Because PacifiCorp's coal procurement strategy and practices are very complex processes, the company believes a workshop with further dialogue between the company and parties would be beneficial. The workshop approach worked well following the 2017 TAM and, due to the complexities of the issues, PacifiCorp believes that the same approach here would be more beneficial than a report.

SIERRA CLUB'S COAL RECOMMENDATIONS

Q. Please describe Sierra Club's analysis and model of the Naughton plant's coal costs in 2015 and 2016.

A. As a result of corrections Sierra Club made to its analysis, Sierra Club no longer recommends an adjustment of $2.4 million. Sierra Club continues to claim, however, that PacifiCorp dispatched the Naughton plant uneconomically and that customers "would have been better off had PacifiCorp been able to burn only [redacted] tons of coal in the year studied, rather than the [redacted] tons actually burned"[21] in the July 2015 to June 2016 contract year.

Q. Please explain why the [redacted] ton scenario proposed by Sierra Club would be harmful for customers.

A. Sierra Club fails to include in its [redacted] ton scenario the minimum take-or-pay contractual obligation of [redacted] which would have been triggered by reducing

[20] Staff/400, Gibbens/23.
[21] Sierra Club/200, Vitolo/6.

the coal purchases to [redacted] tons. After taking into account the additional [redacted] [redacted] in damages stipulated per the Naughton CSA, Sierra Club's calculation of [redacted] "Revenue Minus Coal Cost" [22] would have been [redacted], a very unfavorable result for customers.

Q. Please explain the method PacifiCorp uses to calculate consumed coal expense at the Naughton plant.

A. PacifiCorp's actual consumed costs are calculated using the average cost inventory method. As coal is purchased, the tons and dollars associated with that coal is added to the existing coal stockpile balance account. The total beginning stockpile dollars plus the coal purchased dollars divided by the corresponding tons results in a rate of total dollars per ton available to be consumed. This rate is then applied to the total tons consumed for the month. The assumption is that the cost of inventory is based on the average cost of the coal available for consumption during the month. This inventory methodology is used at all of PacifiCorp's coal plants.

Q. Please explain the problems with Sierra Club's calculation of consumed coal expense in its model for the Naughton plant.

A. First, Sierra Club utilized the first-in, first-out (or FIFO) inventory method. PacifiCorp's actual consumed costs are calculated using the average cost inventory method, as stated above, and were provided to parties along with actual purchased costs and inventory data. Because Sierra Club utilized PacifiCorp's actual average cost data and then input that into their FIFO model, the model is flawed and not comparable.

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[22] Sierra Club/200, Vitolo/5.

Second, at the Naughton plant, the actual contract year runs from July to June, not November to October as suggested by Sierra Club.[23] The lower priced, tier-2 purchased coal prices are typically experienced in the months of May and June. Due to the average cost inventory method used by PacifiCorp, the consumed prices seen in May and June are somewhat lower than other months due to the averaging impact of the pricing tiers, but are not as low as the purchased coal price during these months. The significantly lower price in October 2015 noted by Sierra Club was due to a one-time [redacted] credit for a 2010 to 2011 severance tax true-up that was appropriately charged directly to coal expense, not the inventory. This lower coal expense pricing in October 2015 was not due to the contractual tier-2 price in effect. PacifiCorp's calculation of the one-time October 2015 coal expense rate is shown in Sierra Club's own work papers.[24]

Q. Sierra Club maintains that "multi-year minimum-take contracts are substantially riskier"[25] than short-term contracts. Is this accurate?

A. No. This issue was addressed at length in the reply testimony of company expert Mr. Seth Schwartz. As noted by Mr. Schwartz, there are many risks associated with pursuing additional short-term contracts. Multi-year contracts reduce or eliminate the risk to customers associated with upward market price fluctuations. Minimum-take contracts reduce or eliminate the risk associated with coal supply availability. It is substantially more risky if PacifiCorp had no fuel for electricity generation during certain times of the year.

[23] Sierra Club/200, Vitolo/4.
[24] PAC/1001 (excerpt from Vitolo Confidential Workpapers_Dispatch Analysis CONF 20170801 showing [redacted] credit to coal expense as a one-time cost).
[25] Sierra Club/200, Vitolo/10.

Staff opposes Sierra Club's recommendation that the Commission direct PacifiCorp to refrain from entering into new multi-year coal agreements because "it is an unreasonable risk to customers to impose a blanket prohibition."[26] PacifiCorp has been tasked by its regulators to provide low-cost and reliable electricity. Both multi-year contracts and minimum-take contracts assist in achieving that directive.

UPDATE ON JIM BRIDGER COAL SUPPLY AGREEMENTS

Q. Please describe the status of the pending third-party coal supply and transportation agreements for the Jim Bridger plant.

A. PacifiCorp is continuing to negotiate contract terms with our plant co-owner, Idaho Power, as well as with the Black Butte mine and Union Pacific Railroad. Term sheets, however, have not been finalized. The estimated pricing included in the reply update remains a valid projection. PacifiCorp plans to discuss the final contract terms at the upcoming Jim Bridger long-term fueling plan workshop.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[26] Staff/400, Gibbens/22.

Docket No. UE 323
Exhibit PAC/1001
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Dana M. Ralston

Excerpt from Confidential Workpapers of Thomas Vitolo on October 2015 Naughton Coal Costs

August 2017

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