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August 2, 2017

Via Electronic Filing and US Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 1088
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RE: Docket No. UE 323 In the Matter of PACIFICORP, PACIFIC POWER, 2018 Transition Adjustment Mechanism.

Enclosed for filing is Staff Rebuttal and Cross-Answering Testimony in UE 323, Certificate of Service and UE 323 Service List.

Exhibit 400, pages 8, 18 and 19 are confidential.
Exhibit 402 is confidential

Exhibit 500, pages 5-7, 9-10, 20, 23, 25, 27, 31, 32, 35-36, 40, 42, 47, 48-50 and 52-53 are confidential
Exhibit 502, 505 and 506 are confidential.

Exhibit 600, page 13 is confidential.

Confidential pages and exhibits/attachment will be provided to parties who have signed Protective Order No. 16-128 via US mail.

/s/ Kay Barnes
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CERTIFICATE OF SERVICE

UE 323

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 2nd day of August, 2017 at Salem, Oregon

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UE 323 – SERVICE LIST

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CASE: UE 323
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Rebuttal and Cross-Answering Testimony

<u>REDACTED</u>
August 2, 2017

Q. Please state your name, occupation, and business address.

A. My name is Scott Gibbens. I am a Senior Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I present a portion of Staff's analysis of other parties' opening testimony and PacifiCorp's reply testimony. I will be summarizing Staff's recommendation to the Commission regarding the issues covered in this case. I will also discuss Staff's analysis of the following issues:

- Energy Imbalance Market (EIM)
- Sierra Club's Opening Testimony

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared two exhibits in my rebuttal testimony.

Staff/401: Company's response to Staff DR No. 26
Staff/402: Staff's calculation of forecast benefit compared to actuals

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF INTERVENOR ISSUES

Q. Please summarize the issues raised by other parties in their opening testimony.

A. Four other parties filed opening testimony in UE 323: Oregon Citizens' Utility Board (CUB), Industrial Customers of Northwest Utilities (ICNU), Sierra Club, and Calpine Energy Solutions, LLC (Calpine). CUB made recommendations to the Commission regarding the Jim Bridger selective catalytic reduction installation (SCRs), Qualifying Facilities (QFs), Day-Ahead/Real-Time transaction adjustment (DART), and EIM costs and benefits. ICNU raised concerns over DART and recommended model validation be performed. Sierra Club discussed coal contracts, specifically take-or-pay provisions, liquidated damages, and tiered pricing coal contracts and their impacts on PacifiCorp's dispatch of its coal fleet and recommendations for modeling these issues in future proceedings. Finally, Calpine made a recommendation about the valuation of Renewable Energy Credits (RECs) for departing direct access customers, as well as renewed its argument that the Schedule 296 Consumer Opt-Out charge should not be escalated for Schedule 200 customers in years 6-10.

Q. Did Staff discuss any of the issues raised by other parties in its opening testimony?

A. Yes. The majority of issues raised by intervening parties were also raised by Staff in its opening testimony. Staff/200 discusses Jim Bridger SCRs, the

DART adjustment, model validation, and coal plant dispatching. Staff/300 discusses QFs and valuation of freed-up RECs.

Q. How do CUB's recommendations compare to Staff's?

A. Like CUB, Staff recommends the removal of the impact of Jim Bridger SCRs on the plant's operations due to a lack of prudency review. CUB also recommended a reduction to the variance of the DART adjustment, albeit through a different mechanism, where the DART average would not include years where a PCAM adjustment is triggered. For QFs, CUB recommends a three-year historic average be used to decrement the number of QF contracts forecasted to be added to the system, whereas Staff's opening testimony recommended using last year's delayment rate. As an alternative, CUB proposed an annual deferral of new QF costs in order to true-up an over or under collection.

Q. How do ICNU's recommendations compare to Staff's?

A. ICNU recommended a back-cast that was slightly less comprehensive than the model validation recommended in Staff's opening testimony. ICNU's back-cast would cover only 2016, which may be easier to implement; however, Staff believes that once a single year back-cast is performed, additional years could provide further insight at a lower marginal cost. ICNU's DART adjustment looked at transactions which are not included in PAC's current mechanism, namely transactions performed beyond seven days in advance. It also recommended only using historic data which occurred once PAC joined the EIM. Like Staff, ICNU is attempting to reflect a more accurate representation of the costs of transactions which GRID does not currently include.

Q. How do Sierra Club's recommendations compare to Staff's?

A. Sierra Club looked at the historic dispatch of the Naughton Coal plant and analyzed actuals against different potential realities. Although the analysis performed was unique, like Staff, the inherit assumption was that the coal plants may not be modeled in GRID in the most economic manner. As noted later in my testimony, the resulting recommendations may not be supported by Staff, but the analysis points to a concern which Staff is hoping to alleviate with its updated proposal.

Q. How do Calpine's recommendations compare to Staff's?

A. Staff did not make an explicit recommendation regarding REC valuation in its opening testimony, and reserved its right to respond to the proposals from other parties. Calpine recommended several alternatives. The first was similar to PAC's recommendation except that the value of the REC to be credited to departing direct access load not be based on the incremental value of delayed compliance, but rather on the current value of the RECs. Calpine also recommended the transfer to or retirement on behalf of the direct access customer in lieu of a REC valuation method.

Q. Does Staff provide a more comprehensive discussion of other parties' issues?

A. Yes. Please see the list below which provides where in Staff's rebuttal testimony particular issues can be found:

- Staff/400
    - Coal Contracts
- Staff/500
    - DART
    - Back-cast/Model Validaiton
    - Economic Shutdown of Coal Units
    - Coal Costs
- Staff/600
    - QFs
    - RECs

Q. Can you provide a summary of Staff's rebuttal position?

A. Yes. Staff believes it is telling that the majority of the parties took issue and proposed adjustments for many of the issues Staff was concerned with. Staff does not agree with all of the adjustments proposed by other parties, as described more fully below and by other Staff witnesses, but sees merit in many of the other parties' reasoning. The Company responded with thoughtful and thorough testimony. Staff did not agree with many of the positions taken by the Company but Staff incorporated all valid points into its updated position. Overall, Staff continues to recommend at least a modified version of many of its original positions due to the fact that PacifiCorp's response testimony does not address any of the root problems which Staff sees with the GRID model. The biggest of these being a deficiency in understanding by all parties as to the causal relationships within the model and a lack of accuracy in modeling. To be clear, Staff understands the GRID model methodology. Staff's opening testimony proposed adjustments to less than three percent of the total NPC requested in UE 323. More importantly though, Staff's recommended adjustments seek to improve GRID accuracy, reduce confusion and promote the efficiency of future TAM proceedings. As discussed more fully by Staff witness Dr. Kaufman, a main point of contention for Staff is the performance by PacifiCorp of model validation. Staff is concerned that even after discussions in the UE 307 TAM, the resulting TAM workshops, and proposals by multiple parties in the current TAM filing, the Company is still unwilling to perform the type of analysis which would provide meaningful insight into the issues of GRID and its various adjustments. Staff contends that the introduction of the DART adjustment is evidence that the current TAM model is not an accurate means of forecasting net power costs. This has led to litigating the DART adjustment for the last several TAMs, uncertainty in forecast accuracy, widely varying positions, difficulty in finding common ground for settlement, and frustration among all parties. Staff believes that a thorough examination of GRID is required in order to resolve the deep rooted issues with the GRID model, and the out-of-model DART adjustment.

ISSUE 1: ENERGY IMBALANCE MARKET

Q. Please provide a brief summary of Staff's opening testimony position and recommended adjustment.

A. In my opening testimony, I discussed Staff's concern that the inter-regional benefits (benefit), as forecast utilizing PacifiCorp's current methodology, has led to a chronic under-forecast of actual EIM benefits realized by the Company. I showed that the forecasts consistently produce benefit estimations which are accurate for the previous year's actuals but fail to account for a steady trend in benefits which has been present since PAC joined the EIM. I theorized that the trend could partially be due to new entrants in the market and a learning curve PAC was experiencing; however, in my analysis I was unable to identify clear evidence of these impacts in the data. In an effort to correct for estimates which were a 'year behind,' Staff proposed an adjustment to PacifiCorp's benefit calculation methodology, which included a moderate trend based on half of the actual growth rate present in the historical data.

Q. How did the Company respond to Staff's opening testimony?

A. Company witness Michael Wilding states in his reply testimony:

> In response to Staff's concerns, the company has adjusted its modeling of EIM benefits to rely on the most recent validated operational data, which produces a robust growth rate that is tied directly to the market dynamics that drive the growth in EIM benefits. Staff's adjustment, on the other hand, is arbitrary and not grounded in the market realities that have increased PacifiCorp's EIM.[1]

[1] PAC/400, Wilding/3.

More specifically, PacifiCorp adjusted the methodology from utilizing a 12 month average of the previous year's actual benefits to a modified six month average of the most recent data available.[2] In the new model, PacifiCorp utilizes the three months of data available in 2017, without any escalation, as well as nine months of benefits comprised of the six month average added nine times. This results in a 12 month forecast for 2018. The table below shows an example of the base benefit calculation.

Table 1: Hypothetical Inter-regional benefits

October 2016	November 2016	December 2016	January 2017	February 2017	March 2017
$2 Million	$2.5 Million	$3 Million	$3.5 Million	$4 Million	$4.5 Million

2018 Base Inter-regional benefit: $3.5 Million + $4 Million + $4.5 Million + $3.25 Million * 9 = $41.25 Million

Q. Are there any other components to the Company's methodology?

A. Yes, PacifiCorp also increases the benefit by adding somewhat arbitrary amounts for new entrants and increased solar power impacts. The total increase for new entrants and solar is roughly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the total benefit.

Q. Why does Staff contend that the adjustments for new entrants are 'somewhat arbitrary'?

[2] PAC/500, Brown/2.

A. In PacifiCorp's previous TAM, the adjustment for new entrants was based on an E3 study performed to estimate the impacts of the utility entering the EIM.[3] In this year's TAM, the adjustments are an approximation, based on the PacifiCorp's thoughts on the relative impact of Arizona Public Service and Puget Sound Energy compared to Portland General Electric and Idaho Power Company. The impact is an estimation based on the year/year growth analysis, decremented by what PacifiCorp believes is a reasonable amount given the limitations to believed incremental and decremental capacity constraints.[4] These numbers are arbitrary in that they are not based on an informed study but rather a "best guess" to be added to the benefit calculation. Instead of attempting to guesstimate a complex issue, Staff believes that a data-driven approach to resolving an issue which has yet to be solved is the more rational approach.

Q. PacifiCorp claims its methodology produces a 'robust growth rate.' Does Staff agree?

A. No. Although the proposed methodology produces an increase in EIM benefits over the previous TAM, PacifiCorp's benefit estimation has increased in every year since it joined the EIM. PacifiCorp's proposed methodology does not consider any growth rate or trend in EIM benefits. Instead, it uses what economists call a naïve forecast. Naïve forecasts are simply the most recent data point available, copied over the forecast horizon. This produces a flat line

[3] See UE 296, PAC/500, Dickman/63.
[4] See Staff/401, Company response to Staff DR no. 26.

which extends from the realized data. In PacifiCorp's case, it took a six-month average, copied over the forecast horizon, and added some minor adjustments, most of which were present in its previous methodology which has proven to be insufficient to forecast actual benefits.

Q. Are naïve forecasts accurate?

A. Traditionally, naïve forecasts are used as a baseline forecast, with which more sophisticated models are compared to, to show improvements in forecasting methodology. They are often used in power cost filings to forecast costs which do not traditionally vary much from year to year. Forced outage rates are one such example where a naïve forecast can be used to accurately estimate future costs. With the EIM however, the benefits have not yet reached a point where a naïve forecast is accurate. The data is still progressing upwards to what will eventually become its mean, but historical data does not demonstrate that there has been a leveling of benefits. In its reply testimony PacifiCorp argues that the six months from October 2016 through March 2017 is the timeframe in which the mean will be realized, but provides no data to substantiate this claim.

Q. Can you explain what you mean that the last six months of data need to have the mean realized?

A. The forecast for 2018 will only be accurate with a naïve forecast if the data used to produce the forecast has no trend. The forecast will fail to account for any growth in the six months other than growth due to seasonal reasons. This is because the forecast is based on the assumption that these six months represent 2018 as a whole.

Q. Is it reasonable to assume that the trend has stopped?

A. No. First, PacifiCorp relies on anecdotal evidence that it is no longer experiencing any efficiency gains and has reached a point of diminishing returns. It has not, and simply cannot, prove that there are not other actions which could be taken in order to produce higher benefits for customers. Colloquially, you don't know what you don't know. Second, even if it were true that the Company has completely optimized all of its operations for operating in the EIM, this TAM is too early to remove a trend from the forecast and utilize a simple naïve forecast. PacifiCorp stated that it further optimized its EIM operations in 'late 2016 and early 2017.'[5] This means that PacifiCorp has proven in its own reply testimony that its proposed methodology is insufficient. In order for the naïve forecast to be accurate, the data used to forecast (the last six months) needs to be an accurate representation of the forecast horizon (2018). Any improvement in December or January or February etc. would not be captured in the earlier months like October or November. This is further compounded by the fact that the mis-specification would be multiplied by nine to produce the annual forecast. Consider the example used previously to illustrate the Company's calculation methodology. Assume that the $1.5 million increase between November and February was strictly due to PacifiCorp's improvement in operations and all other assumptions, which the Company

[5] PAC/500, Brown/8.

relies on for its forecast, are true. It is important to note that if all other assumptions the Company makes are true, all of PacifiCorp's operations are fully optimized with regards to the EIM in 2018 and the impact of new entrants is perfectly forecast. The under forecast shown below occurs even if the Company's beliefs are 100% accurate.

Table 2: Hypothetical Inter-regional Benefits

October 2016	November 2016	December 2016	January 2017	February 2017	March 2017
$2 M	$2.5 M	$3 M	$3.5 M	$4 M	$4.5 M

2018 Base Inter-regional benefit: $3.5 Million + $4 Million + $4.5 Million + $3.25 Million * 9 = $41.25 Million

Table 3: Correctly Specified Actuals

J	F	M	A	M	J	J	A	S	O	N	D
$4	$4	$4.5	$4	$4	$4	$4	$4	$4	$4	$4	$4

PacifiCorp's forecast should be $48.5 Million.

In this example, a $1.5 million efficiency gain from improved operations in late 2016/early 2017 results in an under-forecast of $7.25 million.[6] This is part of what has been happening to the Company's forecasts in the past, only

[6] There is a slight issue with the month of October. PacifiCorp's methodology would predict $4 million in benefits if the data were stationary, however the assumption which PacifiCorp's model relies on would suggest the benefits for that month would be $3.5 million. The same as 2016 + technological improvements.

that the trend, which is not captured, has continued every month and has not been static after a single event. It is the reason that customers have seen only 50% of the inter-regional benefits that PacifiCorp has accrued since inter-regional benefits started being forecast in the TAM.[7] Staff does not agree that 2017 will show the end of any efficiency gains or changes for utilities in the EIM. Staff also does not believe in the accuracy of the Company's new entrant adjustment. But even if the Company is correct on both of those points, the above example shows that PacifiCorp's updated methodology will be insufficient to forecast the benefits of the EIM.

In addition to changes PAC went through, all other parties must be accounted for as well. If a new entrant changes its operations, that could provide more opportunities for PacifiCorp to transact in the EIM. Even if only one of the four other members who joined the EIM within the last two years follows a similar learning curve as PacifiCorp, the market would still be in flux, with efficiency gains being realized in 2017 and beyond.

Q. What is the anecdotal evidence PacifiCorp relies on to argue benefits have reached a point of diminishing returns?

A. PacifiCorp admits the single example it uses to support its claim is simplistic. In its argument, PacifiCorp hypothetically cannot back down its generation further because minimum operating levels have been reached. Because of this, PacifiCorp is unable to import more power from the EIM in order to increase benefits. This is so general and unrealistic that it is difficult to begin to critique.

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[7] See Gibbens/402.

Generally, Staff would point out that a further reduction to the EIM price would result in greater benefit to PacifiCorp even if the Company cannot further decrement its production. Unfortunately, this means that the only substantial analysis performed on the diminishing returns theory will be presented after Staff has a chance to respond. However, Staff believes the most prudent forecast is to rely on the historic data, independent of any additional analysis performed by PacifiCorp in response to this testimony. As noted earlier, the argument that “no further improvements can be made” is both a complex argument and inherently impossible to prove. While the Company may present analysis which would require a rational person to temper his or her expectations of growth, Staff has already built this into its recommended adjustment. The most rational forecast to make, in the face of a clear trend, would be to include the trend in the forecast, one for one. However, Staff proposes including 50% of the trend. In a sense, Staff has built into the adjustment the potential that the trend is greatly diminished, and found a middle ground between two alternate possibilities: the first being that the trend has completely stopped, the second that the trend will continue as it has.

This argument in general is similar to one which PacifiCorp made in response to an ICNU proposed adjustment in UE 296 concerning the forecast of benefits in the EIM. Similar to this docket, the Company argued that:

1. New participants could reduce overall EIM benefit to PacifiCorp.[8]

[8] UE 296, PAC/500, Dickman/70, line 5.

2. There are diminishing returns to increasing transmission capacity due to market reactions and company resource limitations.[9]

The result was that only $8,420,559 was forecast for inter-regional EIM benefits in the TAM when in actuality, the company realized over $18 million in inter-regional benefits.[10] UE 327, this year's PCAM is still under review, but as of the initial filing, customers are not set to receive a single dollar of the un-forecasted benefit.

Q. PacifICorp argues that new entrants might decrease its EIM benefits. Does Staff agree?

A. In theory, yes. It is possible, albeit unlikely, that a very similar utility might have the effect that it raises prices when PacifiCorp would normally be importing and lowers prices when the Company is exporting. However, the Company receives benefits through both imports and exports. If a new entrant is more efficient than average, they will drive the market price down, and PacifiCorp will see fewer exports but increased imports. The opposite is true if a new entrant is less efficient than average. Only a utility which raises prices of imports and lowers prices of exports would negatively impact PacifiCorp's benefit in a clear manner. In the end, this potentiality has yet to occur. The data clearly show that inter-regional benefits continue to grow as more participants join.

Q. Did PacifiCorp raise any other concerns regarding Staff's analysis?

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[9] *Id*, Dickman/70, line 9.
[10] UE 327, Initial Application/2.

A. Yes. Some of the concerns raised are peripheral; however those which apply to the central interest, namely Staff's attempt to improve the accuracy of a chronically incorrect forecast, are addressed below:

- "Staff's adjustment is not consistent with the underlying fundamentals of what drives growth in EIM benefits"[11]
    - Contrary to the Company's assertion, it is clear that PacifiCorp's methodology is not consistent with the underlying fundamentals of what drives growth in EIM benefits. A methodology which was consistent with these fundamentals would not result in a forecast with such glaring deficiencies. The Company's critique of Staff's position stems from the fact that Staff's adjustment recommends only an enhancement and not a replacement of PacifiCorp's methodology. Of the year/year growth from 2015 to 2016 in inter-regional benefits, PacifiCorp correctly predicted approximately -2% of it, meaning its forecast predicted a reduction in benefit not an increase.[12] Staff's adjustment takes a clear trend and reduces it partially to account for any potential mitigating impacts.
- PacifiCorp states EIM benefit growth is 56 percent, not 133 percent.
    - Staff finds this argument to be somewhat pedantic. Staff's adjustment is based on inter-regional benefits, which comprise

[11] PAC/500, Brown 10.
[12] When comparing 2015 actuals to 2016 forecast. This was not deliberate by PAC as all 2015 actuals were not available at the time the forecast was made. Similar to the way that 2017 actuals may end up being greater than the Company's 2018 forecast.

the majority of the benefits included in the TAM EIM adjustment. As such, the growth rate that Staff was interested in is that of inter-regional benefits. PacifiCorp, on the other hand, notes that when one includes all benefits, including benefits which are not included in the TAM EIM adjustment and have never been included in the TAM EIM adjustment, the year/year growth rate is 56 percent. This is because intra-regional benefits (between PACW and PACE) have not increased over time, but are superfluous to this discussion. Even still, a growth rate of even 10%, when not accounted for, is a blatant disregard for accuracy.

- Staff overstated its adjustment due to inclusion of a GHG component in calculation.
    - o PacifiCorp correctly points out a mistake made by Staff in its calculation. Staff thanks PacifiCorp for apprising Staff of the error. Staff has revised its adjustment to correct for this mistake.

Q. What is Staff's updated calculation?

A. Yes. First, Staff took a 12 month naïve forecast of the most recent validated data of actual inter-regional EIM benefits, which included April 2016 – March 2017. Staff then added the Company calculated adjustments for new entrants and solar impacts. Finally, Staff took 50% of the calculated the 12-month growth rate from April 2016 to March 2017. This trend was then added to the forecast to gross-up the values to expected 2018 levels. This adjustment maintains the reasoning behind Staff's original adjustment but corrects for the

GHG inclusion and updates the data to the most current validated actuals. The resulting forecast is very close to Staff's opening testimony. Staff's original forecast for total benefits for inter-regional EIM benefits was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, Staff's updated forecast is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.This results in a decreased adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on a total company basis.

Q. Why did Staff utilize a 12-month average instead of a 6-month average like the Company's updated methodology?

A. Staff was concerned with the lack of data on which to build a forecast using only half of a year. This ignores any differences between the benefits realized between months not included in the forecast. While the Company claims that these six months incorporate updated operational tactics, as Staff noted, the Company fails to sufficiently account for trends present in the most recent six months of data.

Q. Please summarize Staff's reasoning for the adjustment.

A. PacifiCorp's methodology ignores a clear trend in EIM benefits. In order for its forecast to be sufficient, the Company would need data which occurred after all of changes to its operations and the market in general had occurred. The problem is the Company made changes in 2017, so the available data is limited. Based on its own operational history, the Company shows that utilities continue to optimize operations well after they join, so it is impossible to know the impacts of new entrants even if the data include all new participants. Inter-regional benefits continue to trend **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** even in the most recent preliminary data,[13] and the Company's methodology has historically under-forecast these benefits by half. Until the data show no upward trend, assuming that next year's benefits will grow in some manner is the most fair and reasonable course of action.

[13] See Staff/402.

ISSUE 2: SIERRA CLUB'S COAL CONTRACT PROPOSAL

Q. Please provide a brief summary of Sierra Club's opening testimony and recommendations?

A. Sierra Club examined PacifiCorp's operational practices and the economic impacts of the coal contracts which the Company has entered into. Specifically, Sierra Club reviews take-or-pay, liquidated damages, and tiered pricing coal contracts. Sierra Club argues that these provisions in PacifICorp's contracts have resulted in the Company dispatching coal plants and planning in the long run in a sub-optimal manner. As a result of its analysis, Sierra Club makes four recommendations:

1. The Commission explicitly direct PacifiCorp to refrain from entering into any new contracts for coal fuel or transportation unless and until the Commission has an opportunity to review whether and how these multi-year commitments in coal contracts are affecting economic dispatch.
2. The Commission reduce the coal-fuel expense increase in the 2018 TAM by $2.4 million.
3. The Commission require PacifiCorp to demonstrate that any unit's dispatch in excess of its corresponding minimum-take quantities was in the best interest of ratepayers in all future TAM proceedings.
4. The Commission direct PacifiCorp in future TAM dockets and other resource planning proceedings to include all variable costs when making decisions regarding unit commitment and dispatch, including real-time, day-ahead, annual, and long-term planning horizons.

Q. How did PacifiCorp respond to Sierra Club's opening testimony?

A. PacifiCorp believes that Sierra Club failed to properly model tiered pricing in its analysis.[14] Sierra Club's model utilizes the average consumed cost of coal instead of the tier-1 price for the calculation of the total coal cost. The Company further claims that it is unreasonable to assume that coal could be procured at the same price with a reduced or non-existent minimum take provision.[15] PacifiCorp also states that the ramp-rate assumption is unrealistic. The Company ask that the Commission reject Sierra Club's proposed adjustments in part based on the following reasons:

1. Rates should be set on a prospective basis, so imprudent operations in the past are not a fair reason to set future rates.
2. A moratorium on new contracts will harm customers and is not supported by Sierra Club's analysis.
3. The IRP process is a Commission vetted means to analyze medium and long term utility operations. The Commission and Company already have reviews in place to ensure that the least-cost, least-risk plan is in place.

Q. How does Staff respond to Sierra Club's adjustments and PacifiCorp's rebuttal?

A. Staff generally has a mixed response to the proposed adjustments. Staff believes that the analysis points to a potential issue regarding the

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[14] PAC/600, Ralson/10.
[15] PAC/600, Ralson/13.

understanding and process of entering into coal contracts. The analysis and proposed adjustments are somewhat similar to concerns raised by Staff in UE 307 regarding the prudence of coal planning and operations. Specifically Staff believes:

1. It is an unreasonable risk to customers to impose a blanket prohibition on PacifiCorp entering into new coal contracts. The current mechanisms, along with Staff's other proposals, are sufficient to ensure the Company's prudence in new contracts it enters into. A blanket moratorium could have unintended consequences which result in harm to customers. Staff further notes that the Commission always retains the right to impose a prudence disallowance for costs associated with imprudent contracts.
2. Staff finds the analysis performed to be informative, but is concerned that it is an insufficient basis with which to adjust 2018 power costs.
3. Along with Staff's proposal, the current TAM process is sufficient to ensure that any unit's dispatch in excess of its corresponding minimum-take quantities was in the best interest of ratepayers.
4. The inclusion of variable O&M costs in the dispatch decision of coal units in the GRID model is an improvement to the model. GRID should include the most accurate estimate of the true dispatch cost in order to optimize the forecast. Staff agrees with Sierra Club's proposal to include variable O&M costs in dispatch decisions in future TAM proceedings, but clarifies that variable O&M costs should continue to be

recovered from base rates as they are currently. This process mirror's PGE's approach to power cost modeling and provides the model with the best estimate of the cost of dispatching.

5. While Staff does not support the adjustments based on the analysis performed by Sierra Club, Staff believes that there is sufficient reason to require a written report detailing all of the considerations and processes of entering into new long-term coal contracts. Gaining a better understanding of the process and reasoning behind coal procurement will ensure that parties are able to analyze new contracts in a thorough manner. The report should be produced before PacifiCorp files for the 2019 TAM. It should include all reasonable information requested by the parties in this filing. Staff proposes a workshop to define the scope of the report which would then be presented to the Commission for final approval.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 323
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Exhibits in Support
Of Rebuttal and Cross-Answering
Testimony

August 2, 2017

OPUC Data Request 26

Energy Imbalance Market (EIM) - Re: Ms. Brown's work paper titled "TAM workbook EIM benefit" tab "2018 Inter regional" and provide the following information:

Please provide all analysis performed and a narrative explanation which led PAC to arrive at the amounts listed in cells C8, C10, and C12. Did PAC include C12 in its original benefit forecast?

Response to OPUC Data Request 26

The $2 million incremental California Independent System Operator (CAISO) energy imbalance market (EIM) benefits associated with the entrance of Portland General Electric and Idaho Power Company is based on the incremental increase in PacifiCorp's EIM benefits relative to Arizona Public Service Company and Puget Sound Energy - December 2015 through March 2016 versus December 2016 through March 2017. PacifiCorp's estimated increase in benefits is an approximation relative to additional Jim Bridger incremental and decremental capacity that is not currently available in the market due to a lack of West to East transmission. It is not anticipated that additional EIM entrants will create the same size of incremental EIM benefits due to PacifiCorp's resource constraints. Please refer to the Company's response to OPUC Data Request 27; specifically Confidential Attachment OPUC 27, which provides the information used to calculate the incremental EIM benefits.

The amount in cell C12 of Company witness, Kelcey A. Brown's work papers entitled "TAM workbook EIM benefit", tab entitled "2018 Inter regional" is for new entrants and solar impacts. In its original EIM benefit forecast, the Company included a similar benefit to account for new EIM entrants. Please refer to the Direct Testimony of Company witness, Michael G. Wilding; specifically page 26.

CASE: UE 323
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 402

Exhibit in Support of Rebuttal and Cross-Answering Testimony

August 2, 2017

Staff Exhibit 402 is confidential and

Is subject to Protective Order No.16-128.

CASE: UE 323
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Rebuttal and Cross-Answering Testimony

<u>REDACTED</u>

August 2, 2017

Q. Please state your name, occupation, and business address.

A. My name is Lance Kaufman. I am a Senior Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes, I provided opening testimony as Exhibit Staff/200.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to PacifiCorp reply testimony, and CUB and ICNU opening testimony related to Net Power Cost (NPC) forecast error, Day-Ahead and Real-Time transaction adjustment (DART), economic shutdowns of coal plants, and Cholla Plant liquidated damages.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

Staff/501: PacifiCorp Responses to Data Requests
Staff/502: PacifiCorp Confidential Responses to Data Requests
Staff/503: Model Validation Reference
Staff/504: EIA Retrospective Gas Prices
Staff/505: PacifiCorp Coal Plant Shutdowns
Staff/506: Cholla Coal Workpapers

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, NPC FORECAST ACCURACY

Q. Please review the parties comments related to NPC forecast accuracy.

A. Staff and ICNU have raised a concern that the Company's NPC model is not accurate.[1] PacifiCorp agrees with this point, and has claimed that the main driver of its NPC forecast error has been related to day ahead and real time transactions.[2] Staff is concerned that there are many other factors driving PacifiCorp's NPC forecast error,[3] and that without a thorough analysis of the historic error, the use of out-board adjustments has the potential to further reduce the accuracy of PacifiCorp's NPC forecast.[4]

Q. What do Staff and ICNU propose related to PacifiCorp's forecast accuracy?

A. Staff and ICNU propose that PacifiCorp systematically analyze its NPC forecast model to help identify the sources of historic error. Staff and ICNU propose a model validation technique, which parties have termed a "backcast." The term was used in the more colloquial sense, but Staff notes that the correct terminology for the proposed analysis is "Model Validation."[5] Staff proposes to use the Model Validation method of comparing the model NPC results from actual historical input values to the actual NPC results. Model Validation is an important component of evaluating system simulations such as

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[1] PAC/400, Wilding/43 to Wilding/45.
[2] Docket No. UE 296, PAC/200, Graves/2.
[3] Staff/200, Kaufman/5 to Kaufman/8.
[4] See Staff/200, Kaufman/8.
[5] A backcast is a specific statistical technique that is distinct from Model Validation and is not appropriately applied to the proposed analysis. In the interest of using technically correct language Staff urges parties to not use the term "backcast" to refer to Model Validation techniques.

GRID.[6] The value of performing the proposed Model Validation analysis is that it can differentiate between errors related to inputs[7] (such as forecasted gas prices, or retail sales) and errors related to model specification[8] (such as missing model inputs, or inappropriate model mechanics). It can also provide a controlled environment to test the performance of NPC model changes.[9]

Q. What is the Company's response to Staff's and ICNU's proposals?

A. The Company dismisses Staff's proposal as having little value.[10] The Company's response is that the best method of addressing model accuracy is to compare model forecast NPC to actual NPC. The Company argues that GRID should not be subjected to Model Validation because:

1. The GRID model operates differently than PacifiCorp's system;
2. The GRID model has perfect foresight; and
3. The NPC forecast is normalized.

Despite these three points, the Company insists that model changes be evaluated based on the accuracy that they bring to the GRID model. PacifiCorp's concerns do not contradict Staff's position that controlling for input errors will help demonstrate whether model changes improve accuracy.

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[6] Staff/503, Kaufman/2.
[7] Staff/200, Kaufman/5.
[8] Staff/200, Kaufman/7.
[9] This is accomplished by evaluating whether a particular model change improves, or worsens the input-output transformation.
[10] PAC/400, Wilding/48.

Q. What is the problem with the Company's proposal for evaluating GRID?

A. The Company's proposal is to only compare forecasted to actual NPC, without controlling for input error. The Company provides no insight into the source of model error. Comparing actual to forecast can only identify the presence of model error. As a result, it does not provide any method of *improving* the model, or increasing the accuracy of forecasting NPC. In short, the Company's proposal does not address or help to identify the flaws in the GRID model that are driving the Company's under-forecast.

Q. PacifiCorp's reply testimony claims that Staff "acknowledges that PacifiCorp has persistently under-recovered its actual NPC since at least 2008."[11] Please respond to PacifiCorp's interpretation of Staff's testimony.

A. PacifiCorp leaves out an important aspect of Staff's analysis of PacifiCorp's NPC forecast error. Staff notes that it is important to distinguish forecast error from model error. The existence of forecast error by itself is not an indication that a model is wrong or has missing components. On the other hand, input error can create forecast error even if a model is correct.[12] For example, even if PacifiCorp's forecast model is perfect, if PacifiCorp's actual coal costs are different than those used in the forecast, PacifiCorp's NPC forecast will be wrong.

[11] PAC/400, Wilding/45.
[12] Staff/200, Kaufman/5 and Kaufman/6.

Q. Can you expand on the coal example using PacifiCorp's past NPC proceedings?

A. A recent example of this is PacifiCorp's 2015 TAM and PCAM. The table below summarizes PacifiCorp coal costs.[13]

[BEGIN CONFIDENTIAL]

Figure 1 Jim Bridger Coal Cost

[redacted]

[END CONFIDENTIAL]

In 2015, PacifiCorp anticipated that coal generation at Jim Bridger would cost **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh.[14] In actual operations coal generation at Jim Bridger cost **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh.[15] Actual power costs in 2015 were **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than they would have been had coal been priced correctly.[16] The results of the 2015 PCAM show that PacifiCorp under forecasted system NPC by approximately $72.6 million. This means that **[BEGIN**

[13] This summary table is based on PacifiCorp's responses to OPUC Data Request 4 and ICNU data request 11.
[14] Figure 1.
[15] Figure 1.
[16] Figure 1.

CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]** percent of the forecast error can be attributed to a single factor, **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Q. Can you provide an example from PacifiCorp's past NPC proceedings demonstrating how accounting for input error can highlight the existence of model specification error?

A. PacifiCorp's 2016 NPC proceedings provide a recent example of how identifying model input error can help to identify model specification error. The 2016 TAM was the first TAM that included the use of the DART adjustment. The NPC forecast error in 2016 was also relatively small compared to prior years. Closer examination of the inputs to the 2016 NPC forecast highlights that there were actually at least two countervailing forces at work, a fuel cost input error and a DART error.

The 2016 NPC forecast used a fuel cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh for Jim Bridger.[17] In actual operations fuel costs were **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh.[18] If actual fuel costs had been equal to the original forecast, 2016 NPC would have been **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[19] The fact that the NPC forecast was close to the actual cost indicates that there must have been a second error working in the

[17] Figure 1.
[18] Figure 1.
[19] Figure 1.

opposite direction as the coal cost input error. This can be seen in the formula below:

$$NPC\ Error = Jim\ Bridger\ Coal\ Error + DART\ Error + Other\ Error$$

[BEGIN CONFIDENTIAL]

$\$0.5\ (NPC\ Error) =$ [redacted]

[END CONFIDENTIAL][20]

Staff notes that 2016 was the first year that the DART model adjustments were incorporated into the TAM and that these model adjustments could account for part of the offsetting "Other Error." The 2016 DART adjustment was approximately $32 million dollars on a system basis,[21] while actual 2016 DART costs were about **[BEGIN CONFIDENTIAL]** [redacted].[22] **[END CONFIDENTIAL]** This means the 2016 DART model error was about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the opposite direction of the 2016 Jim Bridger coal cost error.

Q. Are the coal cost forecast errors likely to persist?

A. No. The primary driver of this **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** was a $30 million mining accident requiring the abandonment and write-off of the recently purchased Joy Longwall Miner.[23] It seems unlikely that PacifiCorp will experience another costly mining accident.

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[20] Values in millions of dollars. $0.5 million in NPC error is calculated from PAC/400, Wilding/43 by multiplying the Oregon 2016 error by four.

[21] Calculated as four times the Oregon only adjustment. See Docket No. UE 296, PAC/100, Dickman/30, line 8.

[22] PAC/400, Wilding/24, Figure 4.

[23] The Bridger Coal Company purchased the Joy Longwall Miner in September of 2015 for approximately $20 Million. Docket No. UP 328 Compliance Filing dated November 20, 2015. In December of 2015, the Joy Longwall Miner became inoperable. The miner was abandoned in

If the coal cost input had not been closely examined, the 2016 TAM forecast would appear to validate the claim that the model was accurate. However in reality, it was simply random chance. A mining accident inflated actual costs and obscured the presence of other offsetting errors. Staff's proposed Model Validation can control for random events such as the loss of the Joy Longwall miner. By controlling for such events, it is possible to determine if there are systemic problems with the GRID model itself.

Q. How do the two examples above highlight the problem with PacifiCorp's approach to NPC model analysis?

A. PacifiCorp's approach to NPC model analysis is to ignore the impact of incorrect model inputs, and to instead focus on the total difference between forecasted and actual NPC. PacifiCorp claims that 2016 operations provide evidence that the DART adjustment improved the accuracy of the NPC forecast. In reality, if PacifiCorp had accurately forecasted coal prices the NPC forecast would have been too high. This is exactly the situation that Staff anticipated in UE 307. PacifiCorp arrives at this faulty conclusion because PacifiCorp is judging accuracy based on a faulty criterion, the comparison of forecast to actuals. PacifiCorp argues against performing a Model Validation method to evaluate 2016.

October 2016 after BCC spent $11 million in recovery efforts. Comments of the Commission Staff, Idaho Public Utility Commission, Case No. IPC.E.I7-06. After this testimony was substantially complete PacifiCorp filed responses to inquiries about the Longwall miner. PacifiCorp's responses are included in Staff/501.

Q. It seems somewhat contradictory to claim that the goal of a forecast is to be accurate, but that analysis of the forecast should not be based on a comparison of forecast to actual values. Shouldn't parties be satisfied that the 2016 forecast NPC was close to actual NPC? Please clarify this apparent contradiction.

A. There are two key reasons why a simple comparison of forecast to actuals is not sufficient:

1. There are not enough data points from a consistent model to make statistically valid conclusions; and
2. The simple comparison does not provide useful information for developing model improvements.

Not enough data points

Staff has shown how input errors can lead to NPC forecast errors. PacifiCorp should strive to use accurate inputs. Parties should expect that the NPC inputs are not biased. For example, in some years, actual coal costs may be lower than the forecast input, and some years they may be higher, but over time the errors average out to zero. However, it may take many years for this averaging process to take effect.[24] For example, in recent years the Energy Information

[24] Figure 1 above demonstrates that PacifiCorp experienced **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Jim Bridger coal cost error in 2012 through 2014 compared to 2015 and

Agency (EIA) has persistently under-forecasted gas prices.[25] The EIA's retrospective analysis of gas price forecasts shows significant serial correlation in forecast error. This means that ten years does not provide enough years of NPC cost comparisons to expect this averaging process to take effect.

Compounding this problem is the fact that PacifiCorp regularly changes the NPC forecast model. Model changes confound the interpretation of multi-year analysis. Even if there were enough data points to reliably average out model input error, PacifiCorp's regular model changes would preclude a meaningful comparison. There are simply not enough data points from a consistent model to draw meaningful conclusions from the simplistic analysis proposed by PacifiCorp.

Simple comparison does not inform model improvements

A simple comparison of NPC forecast to NPC actuals does not provide insight into the source of forecast error. It can only identify the existence of forecast error. Parties cannot develop or evaluate model improvements without identifying the source of model errors. Model Validation analysis, however, does allow parties to explore the source of forecast error, and therefore contributes to the process of model improvement.

Model Validation analysis allows parties to explore forecast error by:

- Identifying which inputs are incorrect;
- Identifying the impact of incorrect inputs on the forecast; and

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2016 but even over five years the average error remains high, at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[25] See Staff/504.

- Performing model adjustments within a controlled environment.

Staff's proposal requires a review of actual data, and a transformation of actual data into input data. This will allow for an apples to apples comparison between actual and forecasted inputs, and allow parties to easily identify which inputs have consistent problems.

Once a set of actual model inputs has been developed, parties can toggle actual and forecasted inputs to determine the impact that the inputs have on the ultimate NPC forecast.

If parties have proposed modeling changes, these changes can be evaluated by performing a side by side Model Validation with and without the proposed changes over a multi-year period. This allows parties to rigorously test model changes in a controlled environment, rather than relying on actual implementation to evaluate the impact.

Q. Please summarize the difference in the application of PacifiCorp's proposed model evaluation and Staff's proposed model evaluation when considering the validity of specific model changes such as the DART adjustment.

A. Under PacifiCorp's approach to testing model changes, parties can only make one change at a time, and must wait three years before seeing the impact of the changes in a single year of operation. Under Staff's approach to testing model changes, parties can develop and test the impact of multiple alternative changes on multiple years of data without waiting and without implementing potentially erroneous changes in rates.

Q. PacifiCorp has raised a concern that Staff's proposal is too burdensome to implement. What is Staff's response?

A. Staff notes that PacifiCorp's annual system NPC forecast is over $1.5 billion dollars.[26] The amount of money involved in this forecast justifies budgeting time and resources for Model Validation. PacifiCorp makes the following claims related to the burden of the analysis:

- A model validation "study will be very laborious because actual data is not always in the necessary format or at the necessary level of granularity required to be a GRID input."[27]
- "Even performing a [Model Validation] of a single year … will be burdensome."[28]

PacifiCorp's NPC forecast inputs are also not always in the necessary format or the necessary level of granularity required to be a GRID input. In fact, they are often less granular than the actual date. For example, the GRID input for market prices begins as a monthly high load hour low load hour forecast. This is then shaped into an hourly price curve, and restructured into a text file that can be read by GRID.[29] PacifiCorp performs the supposedly laborious task of shaping GRID inputs for every TAM update. PacifiCorp has developed a set of

[26] PAC/402, Wilding/5.
[27] PAC/400, Wilding/48.
[28] PAC/400, Wilding/48.
[29] Docket No. UE 307, Staff/200, Kaufman/7 and Kaufman/8.

tools to help automate the process of transforming inputs into the GRID format.[30] It is reasonable to expect that economies of scale such as those gained through automated data transformations make the incremental process of validating additional years less burdensome than the initial process of validating a single year.

Q. Please summarize Staff's recommendation on this issue.

A. Staff recommends the following:

- The Commission open an investigation to establish an appropriate Model Validation process;
- PacifiCorp be required to implement a Model Validation on at least five years of historic operations prior to filing the next TAM; and
- PacifiCorp be required to file the current year results of the Model Validation on a going forward basis within the PCAM.

[30] Staff/501, Kaufman/++ PacifiCorp Response to Staff DR 44.

ISSUE 2: DAY-AHEAD REAL-TIME TRANSACTIONS

Q. Please provide an overview of the DART adjustment and Staff's current assessment of it.

A. Fundamentally, the DART adjustment is an out-of-model adjustment with virtually no relationship to forecasted operations or market conditions. The Company has developed it to address its NPC forecast error. PacifiCorp's under-recovery of NPC stems from an under-forecast of NPC in the TAM; however, as discussed previously, PacifiCorp has not clearly demonstrated why it has historically under-forecasted NPC. The Company asserts that this under-recovery is "largely" due to actual market transaction costs that are not fully reflected in the original NPC model but does not provide evidence to support this assertion. The Company argues that its system balancing purchases occur at higher than monthly average market prices, and that its balancing sales occur at lower than monthly average market prices. In response to PacifiCorp's position, Staff shows the following:

- The historic under-recovery can be attributed to model input error such as coal costs.
- On a going forward basis, the DART costs may be substantially lower than they were during the three years that PacifiCorp highlighted when originally proposing the DART.
- The backward looking nature of the DART adjustment may introduce additional forecast error.

As PacifiCorp points out in its testimony, the Company's DART adjustment has been controversial since its introduction. Staff, CUB and ICNU have all challenged the Company's inclusion of the adjustment in the three most recent TAM proceedings.

Staff has a fundamental concern with PacifiCorp's proposed framework for evaluating this issue. PacifiCorp relies entirely on a comparison of the NPC variance with and without the DART adjustment, and asserts that the parties' criticisms and improvements to DART should be rejected because no party has demonstrated that a more accurate NPC forecast would result. Because PacifiCorp's recent NPC variance is due to under-forecasting NPC, *any* arbitrary fixed cost adder would satisfy PacifiCorp's standard. However, Staff believes that the standard for evidence is higher. Specifically, the DART adjustment must reduce NPC variance *after* accounting for the impact of GRID input error.

Staff has presented evidence that the Company's DART adjustment is arbitrary and irrational, and does not represent a model of NPC, but rather, is an extra-model adjustment.[31] The adjustment is basically a fixed cost adder based on historic calculations. As such, the adjustment is independent of the fact that market conditions, weather, load, etc., would all be different from the historical years. Staff argues that the DART costs can be fully reflected on a

[31] In Docket No. UE 307 Staff demonstrated that DART adjustment remains substantial even when GRID forecasts no market transactions. This fundamentally conflicts with the underlying rationale of the DART adjustment. Docket No. UE 307, Staff/200, Kaufman/10 and 12.

forecast basis by addressing GRID inputs alone. This would change DART from a fixed cost adder to a forward looking component of the NPC model.

Other parties have also criticized DART. ICNU argues DART costs are highly volatile, and that participation in the EIM fundamentally changes how PacifiCorp transacts in the market, and that the DART adjustment should only be based on post EIM participation data. CUB proposes placing a collar around the DART adjustment tied to the trigger of a PCAM. The Company accepted CUB's proposal.

All parties acknowledge that DART costs are volatile and that they are difficult to forecast. ICNU and Staff argue that on a going forward basis, DART costs are likely to be lower than they were in 2013 and 2014.[32] Staff and ICNU also argue that the second component of the DART adjustment does not make sense.

Q. Does Staff continue to object to the inclusion of the DART adjustment in the TAM?

A. Yes. Staff continues to object to the inclusion of the DART adjustment in the TAM for the reasons discussed in its testimony in UE 294, UE 307 and this case. As discussed above, Staff believes that the source of PacifiCorp's NPC forecast error should be identified by using the Model Validation method, and remedied based on the results of that analysis. Staff acknowledges that there may be merit in refining the GRID model inputs to reflect expected correlations

[32] Staff contends that they will also be lower in 2018 than they were in 2015, due to the EIM learning curve.

between the Company's forecasted retail demand and the Company's forecasted market prices. The value of such an input change is more appropriately evaluated within the context of the Model Validation framework. This notwithstanding, Staff has also proposed modifications to the DART adjustment that Staff believes would be an acceptable interim estimate of DART costs while the Company develops the necessary analytical framework.

Q. Please summarize Staff's recommendation in this case.

A. Staff makes the following recommendations:

- Require PacifiCorp to:
  - Develop a Model Valuation procedure;
  - Implement the procedure for the most recent five years;
  - Implement the procedure in each PCAM on a going forward basis; and
  - Revisit the use and design of the DART mechanism after the Model Validation results are available to other parties.
- Exclude abnormal DART years using one of the following two approaches:
  - Modify CUB's proposal to create a symmetric collar of $30 million NPC forecast variance, or
  - Exclude 2013, 2014, and 2015 from the calculations due to the abnormally high real time transactions and the expectation that real time transactions will be low on a going forward basis.

- Eliminate or offset the second component of the DART adjustment through one of the following mechanisms:
  - o Make the cost of "additional balancing transactions" zero; or
  - o Reduce the NPC forecast to account for the residual value of monthly and daily transactions.

Q. This is a complex issue. What part of this issue do you think is most important to review?

A. There are three important aspects that the Commission should consider closely:

1. The analytical framework that Commission should require when judging DART;
2. Whether historic DART costs are representative of future DART costs; and
3. Whether the "additional balancing transactions" component of DART represents a real cost incremental to those modeled through the GRID input component of the DART adjustment.

The first issue addresses whether the Commission should accept PacifiCorp's proposed framework for evaluating the DART impact on NPC variance and whether the Commission should require PacifiCorp to control for input related errors such as coal cost. The second issue addresses CUB's concern that the DART adjustment be properly normalized, ICNU's concern that the EIM results in lower DART costs, and Staff's concern that 2013, 2014, and 2015 were abnormal years. The third issue addresses ICNU's concern that the DART adjustment is really a single adjustment, and Staff's concern that the DART adjustment is not responsive to the expected number of transactions in GRID. The third issue also addresses Staff's concern that the DART adjustment does not account for the residual value of daily and monthly transactions.

The Commission should adopt Staff's proposed framework for evaluation.

Q. The Company states that there is "undisputed evidence that the NPC forecast with the adjustment is more accurate than without [the DART adjustment.]"[33] What evidence is the Company referring to?

A. The Company is likely referring to its comparison of past NPC forecast variances, and what the variances would be with and without the DART adjustment. In an effort to evaluate DART, parties requested that PacifiCorp evaluate DART within the context of the Model Validation analysis.[34] PacifiCorp declined to provide the Model Validation analysis, and instead provided parties with a comparison of actual and forecasted NPC with and without the DART adjustment.[35] As a relatively fixed outboard cost adder, the DART adjustment does indeed reduce the variance between forecasted and actual NPC. What Staff disputes is that it makes the forecast model on a going forward basis more accurate.

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[33] PAC/400, Wilding/3.
[34] See Exhibit PAC/107, Wilding 1. The referenced page uses the term backcast rather than Model Validation.
[35] Exhibit PAC/107, Wilding/24.

Q. Please explain the difference.

A. As PacifiCorp has noted, the TAM forecast has been lower than actual NPC for several years. Because all the forecast errors are in the same direction, *any* fixed cost adder would reduce the forecast error. The table below reproduces PacifiCorp's "undisputed evidence", and compares it with a DART alternative, Staff's More Accurate Real Time (SMART) adjustment.[36]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

The SMART adjustment clearly outperforms the DART adjustment under the Company's proposed standard. In fact, there is "undisputed evidence" that the SMART adjustment results in a more accurate NPC forecast than the DART adjustment. The SMART adjustment is also a lot easier for parties to understand: simply add $1.5 to the TAM cost per MWh.

Q. What is the problem with both the DART adjustment and the SMART adjustment?

[36] Staff is not proposing that the SMART adjustment be implemented. This adjustment is only presented to illustrate Staff's concern with PacifiCorp's proposed evaluation criteria.

A. From a statistical standpoint, the problem is that there are not enough data points, and the errors do not have sufficient variation. From a modeling standpoint, there is no information about what is causing the error, and so there is no way to judge whether to use DART or SMART. If parties were convinced that the DART adjustment was a real cost, incremental to those already included in GRID, and forward looking, than there would be good reason to choose DART over SMART.

Q. Does the reasoning behind DART make it more useful than SMART?

A. Not necessarily. PacifiCorp's narrative supporting the DART adjustment has been persuasive to the Commission in prior docket. The problem is in the execution of the adjustment. PacifiCorp has created an adjustment that on the surface looks thorough and complex. There is even a cumbersome model to calculate the extra monthly and daily transactions PacifiCorp makes. But it is really just a waste of computing power, because in the end the DART adjustment is simply adding a relatively fixed cost to NPC, in the same manner as SMART.[37]

Q. PacifiCorp notes in its opening testimony that the 2016 TAM was the first TAM to include DART, and it also happens to be a year with low NPC variance. Is this evidence that DART is better than SMART?

A. No. Staff addresses the problem with this interpretation in the section above on Model Validation. The 2016 NPC had abnormally high Jim Bridger coal

[37] ICNU/100, Mullins/10, Lines 1 through 6. Also see Docket No. UE 307, Staff/200, Kaufman/10, line 18 to Kaufman/11 line 12. Staff notes that there are some minor, non-fixed aspects do DART related to how GRID dispatches when the Price Adder component is implemented.

costs. These costs were due to a $30 million mining accident that is unlikely to occur in future years. This is also only a single data point. DART may have outperformed SMART in 2016, but SMART is still a “more accurate” adjustment in 2013 through 2015.

Q. What is Staff’s proposed framework for evaluation?

A. Staff’s proposed framework for evaluation is to create a controlled environment within which parties can compare the performance of DART, SMART, and other permutations. Such an environment should be free from the NPC variance attributable to fuel price error, retail sales, hydro output, and other year to year input variances. This proposal is described in more detail in the Model Validation section above. Staff understands that since PacifiCorp has delayed cooperating with parties in this matter, it may be too late for the Model Validation to inform the current TAM, but proposes that the Commission direct PacifiCorp to conduct this analysis. As discussed more fully below, Staff proposes some interim modifications to the DART adjustment while this controlled model testing environment is developed.

Historic DART costs are not representative of future DART costs

Q. Please summarize the parties’ concerns that historic DART costs are not representative of future DART costs.

A. ICNU, Staff, and CUB each have concerns about the applicability of historic DART costs.

- ICNU notes that DART costs are highly volatile, and difficult to forecast. ICNU is also concerned that the DART adjustment reflect changes in PacifiCorp's operations related to the EIM.
- Staff finds that three years of high DART costs may be abnormal. Staff also finds that DART costs are highly correlated with real time transactions, and that PacifiCorp has substantially reduced real time transactions since joining the EIM.
- CUB is concerned that DART be properly normalized, with outlying years excluded in a similar manner as coal and gas plant outage rates.

Q. Please describe ICNU's concern regarding volatility, PacifiCorp's response, and Staff's response.

A. INCU's third concern is that DART costs have high year to year volatility, swinging from a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[38] ICNU notes the volatility makes DART costs difficult to forecast accurately. PacifiCorp replies that just because something is difficult does not mean that it should not be attempted.[39] Staff observes that ICNU did not propose that PacifiCorp should not forecast DART costs. In fact, ICNU has accepted that DART is here to stay in one form or another.[40]

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[38] PAC/400, Wilding/24.

[39] PAC/400, Wilding/24 lines 21 and 22. Staff notes that this statement by PacifiCorp conflicts with PacifiCorp's position on Model Validation.

[40] This is a fact that PacifiCorp acknowledges earlier in its testimony but conveniently forgets when responding to ICNU's volatility concern.

PacifiCorp's response confirms ICNU's claim that DART costs are difficult to forecast,[41] but misinterprets ICNU's conclusion.

Staff observes that the DART volatility has a particular shape, namely a spike in years 2012, 2013, and 2014.[42] The length of the data are too short to draw conclusions about whether these three years are normal or abnormal. The fact that they are clustered together supports a conclusion that they are abnormal, and that it is appropriate to exclude them as proposed by ICNU. The figure below provides hypothetical data for pre-2011 transactions that illustrates why this data is too short. In this hypothetical example Staff generated random numbers representative of 2011, 2015, and 2016. The figure illustrates that the 2012 to 2015 period could represent abnormal years of DART costs. If this is the case, the average DART cost may actually be negative!

[41] PAC/400, Wilding/24 lines 21 and 22.
[42] ICNU proposes to focus on DART costs inclusive of greater than seven day transactions. The 2012 to 2014 spike is based on ICNU's proposal, modified to reflect PacifiCorp's correction. A similar argument can be made for the DART costs exclusive of the greater than seven day transactions.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. What could explain the spike in observed DART costs?

A. This could be driven by the growth of renewable generation and the impact that renewables have on real time prices. The EIM market is also a response to increased renewable penetration and the need for flexible resources to respond.

Q. Please describe ICNU's concern regarding the impact of EIM on DART costs.

A. ICNU is concerned that PacifiCorp's participation in the EIM may have reduced the Company's need to incur DART type costs.[43] PacifiCorp responds that the balancing costs during the first year of EIM participation were higher than average.[44] PacifiCorp notes that the longer lead time required by EIM makes

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[43] ICNU/100, Mullins/13.
[44] PAC/400, Wilding/28.

the Company more reluctant to enter into market transactions.[45] PacifiCorp's observation lends support to ICNU's concern. If the Company is more reluctant to enter into market transactions, the Company will be more likely to use its generation resources in place of market transactions to meet energy needs. Furthermore, Staff and PacifiCorp both find that EIM participation involved a learning curve. It is not surprising that the first year of EIM operations to not show as substantial a change as following years.

PacifiCorp also fails to acknowledge that the EIM has modified how the Company dispatches its system. The Company appears to be scheduling dispatchable resources in order to have greater participation in the EIM market. In fact, the Company even claims that it run its coal plants when they are uneconomic in order to capture EIM benefits. If the EIM market is driving the Company to schedule thermal resources when it would have otherwise made market purchases than it is reasonable to expect that participation in the EIM had affected the Company's DART costs.

Q. Please describe Staff's concern regarding the relationship between DART costs and real time transactions.

A. Staff developed this concern while evaluating ICNU's proposal to exclude pre-EIM data from the DART adjustment. Staff tested ICNU's claim that the EIM affected PacifiCorp's market transactions by tabulating real time transactions by month between 2011 and 2016. Staff found that 2016 real time transactions were substantially lower than 2013 through 2015. In 2016, PacifiCorp recorded

[45] PAC/400, Wilding/28.

zero real time purchases. This is consistent with PacifiCorp's statement that EIM makes parties more reluctant to enter into market transactions. Staff also found a high correlation between real time transactions and DART costs.[46] The table below summarizes transactions by year and compares them to DART costs.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. The decline in real time sales does not occur until one year after joining EIM. What do you recommend based on this?

A. Given the steep learning curve associated with joining, ICNU's proposal to include 2015 in the DART calculations may not be appropriate. As an alternative, Staff recommends including the three years with low real time sales

[46] The highest correlation was between real time sales and monthly DART costs, with a correlation coefficient of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. A correlation coefficient of 1 is perfect correlation and a correlation coefficient of 0 is no correlation.

as representative of DART transactions. Staff recommends this as a temporary measure until PacifiCorp can provide additional modeling evidence regarding DART.

Q. Please respond to CUB's concern that DART costs may not be properly normalized.

A. CUB proposes placing a collar around the DART adjustment tied to the trigger of a PCAM. The Company accept CUB's proposal. Staff finds that CUB's proposal needs some modifications to be consistent with the stated rationale. CUB's goal was to exclude outlying years from the DART in a similar manner to gas plant outages. Staff finds that CUB's proposal is not consistent with CUB's rationale, because a PCAM is only triggered after exposing the Company to an earnings test. Staff does not see the relevance of an earnings test which is affected by base rates and other non-power cost events. CUB's goal of identifying outlying years is muted by subjecting the collar to both the deadband and the earnings test. Staff is also concerned that CUB's mechanism results in an asymmetrical identification of outliers. If the Commission finds in favor of CUB's approach, Staff recommends modifying CUB's collar to eliminate years in which the NPC forecast deviates from actuals by plus or minus $30 million. This represents a symmetric collar that would identify outlying years regardless of whether the Company is over or under earning due to non-power cost reasons.

Q. What is Staff's recommendation regarding parties' concerns about the applicability of historic DART costs to future years?

A. Staff recommends that the base years for the DART adjustment exclude abnormal years using one of the following two approaches:

- Modify CUB's proposal to create a symmetric collar of $30 million NPC forecast variance, or
- Exclude 2013, 2014, and 2015 from the calculations due to the abnormally high real time transactions and the expectation that real time transactions will be low on a going forward basis.

Additional monthly and daily transaction costs are not incremental to GRID

Q. Summarize the concerns raised regarding the additional transactions component of DART.

A. Staff is concerned that PacifiCorp's model does not appropriately acknowledge the value of residual value of monthly transactions. ICNU argues in a similar vein that greater than seven day transactions should be included in the DART adjustment. DART costs can be fully accounted for with an appropriate adjustment to GRID's inputs. Staff and ICNU are concerned that the second component of DART, which adds costs associated with additional transactions, is really an unnecessarily complicated method of plugging in a fixed number. Staff argues that as a result, the additional transactions component of DART converts it from an appropriately forward looking adjustment into a fixed cost adder akin to the SMART adjustment. The Company is unable to identify specific evidence within the record which shows "the daily and monthly transactions component of the DART adjustment are real incremental to the costs already included in GRID after the implementation of the price adder component of the DART adjustment."[47]

Q. Please restate Staff's concern regarding residual value of monthly transactions, and provide Staff's reaction to PacifiCorp's response.

A. Staff is concerned that PacifiCorp's methodology does not account for the residual value associated with monthly transactions. Residual value exists because PacifiCorp tends to sell off the low value portion of monthly contracts. PacifiCorp's DART adjustment does not account for this residual value because it adds additional DART type costs associated with monthly and daily transactions. Staff demonstrates how monthly transactions can result in real time transactions that deviate systemically from the monthly average price. PacifiCorp responds that this validates the use of the DART price adder. PacifiCorp and Staff agree that the market price inputs should be adjusted to account for DART costs. PacifiCorp's response is consistent with Staff's position. Staff's point is that the additional balancing transactions, which PacifiCorp models outside of GRID as a plugged cost adder, are not real incremental costs. A monthly transaction should be priced based on the average expected price for the month. The only reason a monthly transaction would be incremental to the GRID costs would be if the average expected price is too high or too low.

If PacifiCorp engages in a monthly transaction in order to partially fill its real time transaction needs, then PacifiCorp is satisfying those real time needs at

[47] Staff/501, PacifiCorp's response to OPUC DR 41.

the monthly average price. The monthly transaction does not add to the real time transaction cost that has already been inflated by the price adders.

Q. Please summarize ICNU's concern about greater than seven day transactions, PacifiCorp's reply and Staff's response.

A. ICNU's concern is that PacifiCorp excludes greater than seven day transactions when calculating the historic DART costs and Price Adders. PacifiCorp argues that ICNU's proposal to include greater than seven day transactions "is essentially truing-up the OFPC used in GRID to the historical monthly average price."[48] PacifiCorp's argument is flawed because only a portion of monthly and quarterly transactions are reflected in GRID. The table below summarizes the portion of Short Term Firm transactions that are modeled in GRID.[49]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

The majority of greater than seven day transactions are not modeled in GRID, and so PacifiCorp's claim that ICNU's proposal is a true-up is incorrect. As a sensitivity to ICNU's calculations, Staff recalculated ICNU's Table 2 values for 2015 and 2016, modified to exclude transactions that were executed on or

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[48] PAC/400, Wilding/23 line 16.
[49] Calculated from PacifiCorp's response to OPUC DR 4 and ICNU workpaper "Confidential Exhibit ICNU 104.xlsx".

before November of 2014 and 2015 respectively.[50] This sensitivity should resolve PacifiCorp's concern related to the alleged true-up. Staff's results and ICNU's original calculations are provided below:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Staff's sensitivity analysis shows that even after excluding contracts that were reflected in the final TAM updates, ICNU's proposal still results in substantially smaller DART costs than those requested by PacifiCorp. However, Staff does not support ICNU's proposal. A more appropriate remedy is to the greater than seven days transaction issue is to exclude the "additional balancing transactions" component of DART.

[50] Calculated from PacifiCorp's response to OPUC DR 5 and 6, and from ICNU workpaper "Confidential Exhibit ICNU 104.xlsx".

Q. Please explain why the additional balancing transactions component of DART should be excluded.

A. As noted above, monthly and daily transactions do not create DART costs. DART costs are created by the correlation between demand and market price. This statement is supported by PacifiCorp's outside expert.[51] Monthly and daily transactions simply transform how the DART costs are realized. Consider the example provided in Staff's reply testimony, where PacifiCorp needs 5,000 MWh of market transactions during the part of the month when prices are $30. In that scenarios, the price inputs (the first component of DART) are fixed, and GRID makes a real time purchase at $30 per MWh. Then in the second component of the DART adjustment PacifiCorp says that it needs to add more costs for monthly transactions. But all the monthly transaction does is shift the time period that PacifiCorp incurred the DART costs. If PacifiCorp actually buys the monthly product at $20 per month, then PacifiCorp experiences the DART cost when selling off the excess power during low priced periods rather than buying during high priced periods. By creating the DART price adder, PacifiCorp remedies the DART problem. There is no need to price the additional balancing transactions.

Q. Please recap Staff's recommendations regarding DART.

A. Staff makes the following recommendations:

- Require PacifiCorp to:

[51] UE 296 PAC/200, Graves/7.

  - o Adopt a Model Valuation procedure developed in Staff's proposed investigation from the section above;
  - o Implement the procedure for the most recent five years;
  - o Implement the procedure in each PCAM on a going forward basis; and
  - o Revisit the use and design of the DART mechanism after the Model Validation results are available to other parties.
- Exclude abnormal years using one of the following two approaches
  - o Modify CUB's proposal to create a symmetric collar of $30 million NPC forecast variance, or
  - o Exclude 2013, 2014, and 2015 from the calculations due to the abnormally high real time transactions and the expectation that real time transactions will be low on a going forward basis.
- Eliminate or offset the second component of the DART adjustment through one of the following mechanisms:
  - o Make the cost of "additional balancing transactions" zero; or
  - o Reduce the NPC forecast to account for the residual value of monthly and daily transactions.

ISSUE 3: ECONOMIC SHUTDOWN OF COAL UNITS

Q. Please review Staff's issue related to the economic shutdown of coal units.

A. PacifiCorp performed economic shutdown of coal units in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** 2016,[52] and 2017, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Staff does not have access to data on plant shutdowns prior to 2013. Economic shutdown of coal units occurs when the marginal cost to operate the coal unit is greater than cost of alternate available energy sources. Economic shutdowns reduce power costs. The GRID model is not capable of modeling economic shut-downs of coal units.[53] PacifiCorp NPC forecast has failed to anticipate the cost impact of any economic shutdowns in prior years' TAMs, and the Company proposes no changes to future modeling of economic shutdown.[54]

During periods of low energy costs, GRID operates coal units at the minimum operating level.[55] This limitation prevents GRID from selecting the lowest cost dispatch of plants. Staff proposes to shutdown certain high cost coal plants during periods of low marginal power costs. This is accomplished by performing additional planned outages to PacifiCorp's filed planned outage GRID input files. In reply testimony, Staff identified two potential coal plant

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[52] Staff/505.
[53] PAC/400, Wilding/32.
[54] PAC/400, Wilding/32.
[55] Coal units have a minimum operating level below which they cannot be run.

shutdowns that reduced power costs by $3.7 million dollars. Staff proposes 120 plant days of economic shutdowns, versus approximately 240 actual economic coal shutdown days in 2016.[56]

Q. How does PacifiCorp's reply address the fundamental model flaw that Staff identified?

A. PacifiCorp's reply testimony agrees that GRID is not able to model economic shutdowns, but does not address Staff's claim that this can result in non-optimal dispatch. PacifiCorp proposes that the Commission dismiss the last five years of data indicating PacifiCorp regularly performs economic shutdowns because PacifiCorp does not expect to perform economic shutdowns in 2018. PacifiCorp bases this on expected gas prices and hydro generation.[57] However, the real test of whether to perform an economic shutdown is the market price for electricity.[58]

Q. Does PacifiCorp provide any constructive remedies to GRID's model flaws?

A. No. While PacifiCorp acknowledges the problem with GRID, PacifiCorp fails to propose any appropriate remedies. PacifiCorp notes some potential problems with Staff's approach; however, PacifiCorp does not provide specific details on how it would address the issue.

[56] See PAC/400, Wilding/33. Staff calculated 240 as 3 percent of 8,000.
[57] PAC/400, Wilding/33 and Wilding/34.
[58] Staff asked PacifiCorp to provide the analysis leading to the 2016 coal shutdowns. PacifiCorp recreated the type of analysis that it performed and the dominant factor was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** See Staff/502, PacifiCorp Confidential Response to DR 42.

Q. Has PacifiCorp had sufficient notice to develop a remedy to Staff's concern?

A. Yes. Staff discussed concerns regarding modeling economic shutdown of coal plants during UE 307 technical conferences and the Commission ordered workshops following the resolution of UE 307.

Q. What concerns does PacifiCorp raise regarding Staff's proposal?

A. PacifiCorp raises the following concerns:

1. Staff did not develop a formal rule based mechanism to select shutdown periods;[59]
2. Staff's proposal does not account for coal cost impacts;[60]
3. Staff's proposal results in increased market purchases and fewer market sales;[61]
4. Staff's proposal does not account for operational consideration of EIM participation;[62]
5. PacifiCorp does not expect 2018 gas prices to be as low as 2016 gas prices;[63]

[59] PAC/400, Wilding/32.
[60] PAC/400, Wilding/32 lines 12 to 13.
[61] PAC/400, Wilding/32.
[62] PAC/400, Wilding/32.
[63] PAC/400, Wilding/33 lines 5 to 13.

6. Staff's proposal constitutes a modeling change, and that the change cannot be developed during the time afforded by the TAM's procedural schedule;[64]
7. Staff does not account for APS contract considerations;[65] and
8. Staff's proposal results in two Jim Bridger units offline simultaneously.[66]

PacifiCorp's explanation of these concerns is superficial, with little to no supporting detail or explanation.

Q. Should the Commission be concerned that Staff's approach was intuitive, and did not utilize a formal rule based mechanism?

A. No. As PacifiCorp notes, Staff employed a heuristic approach to identifying economic closures.[67] This approach employed Staff judgment to circumvent the need to develop complex calculations. PacifiCorp appears to prefer a formulaic approach to identifying economic coal closures. Staff's initial testimony on this matter actually highlights that its recommended method was not formalized, and that there is the possibility that Staff's proposed adjustment is understated.

Staff recommends that the Commission adopt Staff's closures on a one time basis, and direct PacifiCorp to develop a more formal process for use in next year's TAM. As PacifiCorp notes, the TAM procedural schedule does not allow time to develop a formal modeling process. Furthermore, the development of a formal modeling process is the Company's role, not Staff's role.

[64] PAC/400, Wilding/34.
[65] PAC/400, Wilding/32.
[66] PAC/400, Wilding/32.
[67] Staff/200, Kaufman/22.

If the Commission is concerned that Staff's adjustment does not identify enough economic closures, the Commission could direct PacifiCorp to test an extended set of coal closures as part of the final TAM update, and select the most economic combination. Staff's recommendation in this case is intended to be a temporary correction, until such time as the Company can develop a more formal modeling method. The value of Staff's intuitive approach is that it allows parties to develop and partially correct one of GRID's flaws within the time frame of the TAM's procedural schedule. A more detailed explanation of Staff's current method is described in Staff/200, Kaufman/22.

Q. Does Staff agree with PacifiCorp that Staff's proposal should account for coal cost impacts of economic shutdowns?

A. Yes. PacifiCorp provides little detail about this concern; however, Staff is sufficiently familiar with the GRID model to understand the point that PacifiCorp was intending to make. Staff's understanding is that a reduction in coal use could affect the average coal cost for a plant. GRID does not update average coal costs, and so PacifiCorp must recalculate the average fuel cost as part of every TAM update. As Staff noted in Staff's opening testimony, the coal costs should be updated to reflect the average unit price of coal after incorporating economic shutdowns. PacifiCorp performs the coal price update regularly, and incorporated a coal price update in its July update. Staff recommends that PacifiCorp update the fuel cost after implementing economic shutdowns to reflect any changes in both the marginal coal cost and the average coal cost.

Q. Is the modeled increase in market purchases and the decrease in market sales a valid reason to dismiss Staff's proposal?

A. No. PacifiCorp provides no reasoned explanation why market purchases during periods of economic shutdowns should be treated any differently than market purchases during other periods of planned outages, or any other time in GRID. Furthermore, PacifiCorp fails to note that fewer market sales means fewer market transactions, not more market transactions. The reduction in market sales under Staff's proposal indicates that GRID was uneconomically dispatching coal, and selling it into the market at a price below the cost of generation. This is not only counter to economic operations, it is counter to Oregon's carbon policy.

In fact, it makes sense for PacifiCorp to displace coal with market purchases if the market purchases are less expensive than coal generation. A change in market purchases should impact the DART adjustment If PacifiCorp's DART model is functioning correctly. Staff's adjustment includes PacifiCorp's version of the DART adjustments, as opposed to the DART changes recommended by Staff. Staff's estimated cost savings of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is after updating power cost for any incremental DART type costs.

Finally, Staff notes that PacifiCorp's own testimony is that thermal outages **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[68]

[68] PAC/107, Wilding/48.

Q. What does PacifiCorp mean by the statement that Staff's model does not account for the operation impact of EIM participation?

A. PacifiCorp is concerned that economic shutdowns could reduce EIM benefits.[69] Staff agrees that any EIM impacts should be incorporated into this adjustment; however, these impacts are likely to be nominal, given that the following:

- The 2016 actual EIM benefit included economic shutdowns that amounted to twice staff's proposed shutdowns; and
- PacifiCorp does not appear to incorporate EIM impacts into the gas screening process when modeling economic shutdowns of gas plants.

Because PacifiCorp has not provided a proposed dollar impact, and because Staff finds that the dollar impact is likely to be small relative to the currently measured savings, Staff does not propose a specific adjustment to EIM benefits. Staff is concerned that if PacifiCorp provides an estimate of the EIM costs in future testimony, parties will not have an opportunity to provide a response to the proposed estimate. Staff requests that any additional PacifiCorp testimony related to the EIM impacts of economic shutdowns be described in detail with transparent workpapers included as exhibits.

Q. Is the fact that 2016 gas prices were lower than the forecasted price for 2018 relevant to Staff's analysis?

A. No. PacifiCorp claims that economic shutdowns of coal plants should only be performed if the plant's power is replaced with self-generation rather than

[69] Staff/501, PacifiCorp Response to OPUC Data Request 43.

market purchases. PacifiCorp claims that the current gas price forecast makes it unlikely that natural gas generation will displace coal generation in 2018.[70] Staff's analysis is not based on what happened in 2016. Staff's analysis is forward-looking, and relies on PacifiCorp's forecasts of market power prices in 2018. Given the expected market prices, it is economical to displace some coal generation with market purchases. Staff also notes that a more relevant comparison for testing the trade-off between gas and coal is between 2018 gas prices and 2018 coal prices. PacifiCorp also fails to recognize that economic shutdowns were performed in **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]**[71] and 2017. The gas price for 2017 was above the projected 2018 price.[72] PacifiCorp does not provide gas prices from 2013, 2014, or 2015. The Commission should place no value on PacifiCorp's analysis of 2016 gas prices.

Q. Is Staff's proposal a complex model change?

A. No, Staff's proposal is only to increase planned outages for two plants. PacifiCorp updates and modifies planned outages in every TAM without notifying parties of the changes. To the extent that Staff's method of selecting the additional planned outages is not optimal, Staff welcomes PacifiCorp to find a more optimal combination of additional shutdowns. This would only decrease forecasted power costs further. As noted above, Staff has raised this concern in prior dockets and PacifiCorp has had sufficient time to develop its

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[70] PAC/400, Wilding/33.
[71] Staff/505.
[72] PAC/400, Wilding/34.

own modeling proposal to address the issue, but has chosen not to do so at this time.

Q. Does Staff agree that the Cholla economic shutdown should account for the APS Exchange?

A. PacifiCorp has provided no details regarding what the APS Exchange is or why it should limit the economic shutdown of Cholla. If PacifiCorp can clearly demonstrate why this is a binding constraint on the operation of Cholla, Staff recommends that the Cholla shutdown be ended on May 15, rather than May 30. Staff recommends that PacifiCorp provide the following information to the Commission to help the Commission determine if it is economical to shut down Cholla after May 15:

- Details of the APS Exchange including any revenues or power transactions associated with it;
- A copy of the APS Exchange agreement;
- An explanation of how the APS Exchange is modeled in GRID;
- An explanation of why Cholla is included as a dispatchable resource in GRID during the period of the APS Exchange;

Q. Is Staff's proposal to shutdown Bridger Unit 1 during a maintenance outage for Bridger Unit 3 consistent with PacifiCorp's past economic shutdown practices?

A. Yes, PacifiCorp has several historic examples of economic shutdowns with multiple Bridger units offline at once.[73] Staff notes that with an economic shutdown, a unit is available to be started in emergencies and is therefore not subject to the same operational considerations given to maintenance related outages, in which plants may not be available for restart until maintenance is complete.

Q. Does PacifiCorp's reply testimony raise any reliability concerns with Staff's proposal?

A. PacifiCorp's testimony gives the impression that there may be a reliability concerns with Staff's proposal by criticizing the simultaneous shutdown of two Jim Bridger units. However, the GRID model modifies dispatch to maintain sufficient reserves, and PacifiCorp's testimony does not directly state that Staff's proposal results in unreliable system operations.

Q. You mentioned earlier that PacifiCorp models economic shutdowns of gas plants. Can you provide additional information on this?

A. PacifiCorp has previously developed a method to identify appropriate periods for shutting down gas plants, called the gas screening process. PacifiCorp has been performing a gas screening process for economic shutdowns of gas plants since at least the 2009 TAM in Docket No. UE 199.[74] The basic process is similar to the process employed by Staff to screen coal plants. PacifiCorp employs a manual process of implementing multiple GRID runs to identify the

[73] See Staff /505, Kaufman/1.
[74] See Docket No. UE 207, PPL(TAM)/100, Duval/13 line 13.

optimal combination of economic gas plant shutdowns.[75] Given PacifiCorp's existing capacity to screen gas plants for economic shutdowns, it is reasonable to expect PacifiCorp to also screen coal plants for economic shutdowns.

Q. Does the screening process for gas plants address the concerns raised by PacifiCorp regarding Staff's screening of coal plants?

A. No. Based on Staff's understanding, the gas screening process does not limit market purchases from being replacement recourses. The gas screening process also does not appear to include consideration of the EIM market. PacifiCorp's concern with replacement market purchases and EIM for economic shut-down of coal is inconsistent with its gas units.

Q. Please summarize your response to PacifiCorp's eight concerns detailed above.

A. PacifiCorp's eight concerns have not caused Staff to change its position that GRID's failure to model economic shutdown of coal plants should be corrected. Staff continues to propose several modifications to the calculated adjustment, conditional on PacifiCorp providing additional supporting information.

Q. Please summarize your current economic shutdown proposal as influenced by PacifiCorp's response.

A. Staff makes the following recommendation:

- Modify the Staff shutdown in the following manner:
  - o Stop the shutdown of Cholla at May 15, if the documentation requested in Staff's testimony demonstrates that PacifiCorp is

[75] See Docket No. UE 207, PPL(TAM)/100, Duval/13 lines 10 through 20.

contractually obligated to run Cholla, and that the costs and benefits associated with the contractual obligation is reflected in the NPC forecast.

- Update coal costs to reflect the forecasted volumes in the shutdown scenario.

- Test Staff's shutdown scenario, and any additional shutdown scenarios contemplated by other parties or the Commission prior to the final TAM update. Select the scenario which results in the lowest NPC forecast.

ISSUE 4: COAL COSTS

Q. Please summarize this issue.

A. Staff and PacifiCorp currently disagree on the appropriate liquidated damages included in base rates. PacifiCorp forecasts burning **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons of coal at Cholla in 2018.[76] However, PacifiCorp only models **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons of coal purchases. The difference is due to a planned drawdown in PacifiCorp's coal pile at Cholla. This means that PacifiCorp's NPC forecast includes **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in additional liquidated damages associated with the planned Cholla coal drawdown. Staff proposes that the liquidated damages be calculated under the assumption that PacifiCorp purchases the same amount of coal that it anticipates burning. This would result in no drawdown of the Cholla coal pile.

Q. Please explain why Staff proposes to model 2018 NPC without a drawdown of Cholla's coal pile.

A. Staff makes this proposal for five reasons:

1. The drawdown costs are more appropriately attributed to past operating years;
2. The drawdown is not necessary, and could be implemented during a time when PacifiCorp is not facing liquidated damages;

[76] PAC/600, Ralston/8.

3. PacifiCorp made an imprudent preliminary nomination for 2018 coal purchases;
4. PacifiCorp could have made coal nominations in a non-binding manner; and
5. Staff's proposal does not preclude PacifiCorp from drawing down the existing coal pile.

The drawdown costs are attributable to 2016 operations

PacifiCorp's initial filing from UE 296 shows a 2016 year end coal pile of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons.[77] However, the actual December Cholla inventory was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons.[78] It was PacifiCorp's 2016 operating decisions that caused the coal pile to grow to the current size. The costs associated with drawing down the Cholla coal pile should be attributed to 2016 NPC rather than 2018 NPC. The Commission should not allow utilities to shift coal minimum take and liquidated damage requirements between years. This will provide utilities with an opportunity to manipulate the results of NPC forecasts and PCAM true-ups.

The drawdown is not necessary

PacifiCorp has planned to operate at the current inventory level for at least one year. PacifiCorp's UE 307 TAM filing models average 2017 Cholla coal inventory of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons, with no substantial drawdown over the 2017 period.[79] PacifiCorp's average

[77] Staff/506.
[78] Staff/502, PacifiCorp Response to Staff DR 30.
[79] Staff/506.

coal inventory from 2013 to 2017 was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons.[80] 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.

PacifiCorp's 2018 preliminary coal nominations were not prudent

PacifiCorp's preliminary coal nominations were not prudent because PacifiCorp did not make the nominations based on up to date information. On July 1, 2017, PacifiCorp nominated **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in purchases.[81] This was**[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** PacifiCorp's initial plan of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons.[82] However, changing circumstances after the initial filing indicate that PacifiCorp's initial plan should have been revised up, not down. The table below summarizes the evidence that PacifiCorp should have increased its nominations. Between PacifiCorp's initial filing and PacifiCorp's July update, the forecasted Cholla January 1, 2018 stockpile decreased by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons, and the forecasted 2018 Cholla coal burn increased by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons. This means that PacifiCorp could have achieved the initially filed December 31, 2018 target stockpile while still accepting **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons of coal. Rather than increase the nominations to meet

[80] Staff/502, PacifiCorp Response to Staff DR 30.
[81] PAC/600, Ralston/8.
[82] PAC/600, Ralston/7.

the revised expectations, PacifiCorp decreased the nominations. There is an **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** day difference between PacifiCorp's initial nomination deadline and the date PacifiCorp filed its July update. This time difference is such that PacifiCorp should have either been aware of the changing circumstances on July 1, or PacifiCorp should have accelerated its planning process to accommodate the coal nomination deadline.

PacifiCorp could have made a coal nomination that did not bind it to either Staff or PacifiCorp's proposed coal purchases.

PacifiCorp's 2018 coal nominations could have been structured to accommodate either PacifiCorp's filed position, or Staff's filed position. As PacifiCorp notes in reply, the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** preliminary coal nomination allows for a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent movement in final nominations. On **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** PacifiCorp proposed coal purchase was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons and Staff's proposed coal purchase was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons. If PacifiCorp had nominated **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons, PacifiCorp could have been positioned to make a final nomination of either **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons. This would have allowed PacifiCorp to make final coal nominations within one percent of either parties' proposed level. The fact that PacifiCorp's nomination was below, rather than at or above, its expected purchase volume, indicates that PacifiCorp's strategy was more likely focused on shareholder outcomes than customer outcomes or Commission flexibility.

Staff's proposal does not preclude PacifiCorp from drawing down the coal pile. Staff's rationale for excluding the costs associated with the coal pile drawdown is primarily a proposed rate treatment. It should not be interpreted as a proposal that PacifiCorp keep the coal pile at questionably high levels. Staff agrees that PacifiCorp should not allow the coal pile to grow to an unmanageable size. If PacifiCorp chooses to draw down the coal pile in 2018, the incremental liquidated damages associated with the draw down should receive the same rate treatment as it would have received in 2016 NPC, as they would have been had PacifiCorp recognized the costs in 2016. An equivalent adjustment is warranted in the 2018 PCAM, but will address that issue in that docket.

Q. You state earlier that allowing utilities to shift liquidated damages between power cost years will provide utilities an opportunity to manipulate the NPC and PCAM results. Can you provide additional detail about how this may work?

A. Consider PacifiCorp's current situation. The table below summarizes Cholla coal inventories.[83]

[83] Calculated from PacifiCorp's response to OPUC DR 30. See Staff/502.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

In 2016, PacifiCorp received substantially more coal at Cholla than it burned, and December coal inventory more than tripled. This could have occurred because PacifiCorp wanted to avoid damages or other contract costs. It is also possible that, as in the 2018 coal nominations, PacifiCorp failed to revise its coal nomination values for changing circumstances. In either case, PacifiCorp avoids recording an unanticipated cost in 2016 by growing its coal stock pile beyond what PacifiCorp alleges is a safe and efficient operating size. The 2016 PCAM shows that PacifiCorp's NPC were within the deadband. This means that had PacifiCorp incurred the 2016 excess coal costs in 2016, PacifiCorp shareholders would have borne all the burden of the excess costs. Instead, PacifiCorp allowed its coal pile to grow to nearly three times the target size, and is requesting to recover the 2016 excess coal costs through the 2018 TAM. This results in customers bearing the burden of the costs.

Q. How does PacifiCorp's historic coal inventory compare to the target?

A. PacifiCorp's target is about half of the 2013 to 2017 inventory average.

Q. Is the issue of shifting liquidated damages from coal pile drawdowns a novel issue for the Commission?

A. No. In PGE's 2017 AUT, Docket No. UE 306, the Commission adopted a settlement in which PGE agreed to accept Staff's proposal that coal piles be modeled with the same starting and ending volume for Boardman coal pile during periods when the plant is faced with liquidated damages.[84]

Q. PacifiCorp states that "Staffs adjustment ignores the terms of the Cholla CSA."[85] Is this accurate?

A. No, this is not accurate, PacifiCorp did not disclose this component of the Colla CSA amendment to Staff or other parties.

Q. PacifiCorp states that because the amended CSA's gives Peabody the right to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Staff's proposed damages is not possible.[86] Please respond.

A. PacifiCorp provides no evidence that Peabody will exercise its **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. PacifiCorp also provides no evidence that the liquidated damages applies if Peabody declines to deliver. The amended CSA appears to leave open the option of receiving more than **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons, and therefore there is not an effective cap.

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[84] Order 16-419, Appendix A, Page 2.
[85] PAC/600, Ralston/9.
[86] PAC/600, Ralston/9.

Q. Does this conclude your testimony?

A. Yes.

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PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 501

Exhibits in Support
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August 2, 2017

OPUC Data Request 30

Please provide the monthly coal inventory level for Cholla 4 from January 2013 to present.

Response to OPUC Data Request 30

Please refer to Confidential Attachment OPUC 30 (Coal Inventory Level tab), which provides the confidential month end coal inventory levels for Cholla Unit 4 from January 2013 to June 2017.

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 41

Please refer to PAC/400 Wilding/12.

(a) Please provide page and line citations to PacifiCorp's testimony which constitutes evidence that the daily and monthly transactions component of the DART adjustment are real incremental to the costs already included in GRID after the implementation of the price adder component of the DART adjustment.

(b) Please provide all invoices from the Brattle Group to PacifiCorp in 2014, 2015, and 2016. Please indicate which invoices relate to the testimony from the outside expert in Docket No. UE 296.

(c) Please provide all data provided by PacifiCorp to the outside expert in Docket No. UE 296 related to the DART adjustment.

Response to OPUC Data Request 41

(a) PacifiCorp objects to this request as unreasonably burdensome in that the Company's testimony on, as well as the Public Utility Commission of Oregon's (OPUC) decisions approving, the day-ahead real-time (DA-RT) adjustment are publically available. Without waiving this objection, the Company responds as follows:

Please refer to the DA-RT adjustment sections in the Company's Direct Testimonies, Reply Testimonies, Rebuttal Testimonies and Surrebuttal Testimonies that the Company submitted in the current transition adjustment mechanism (TAM) - docket UE 323 and past two TAMs – docket UE 307 and docket UE 296.

(b) PacifiCorp objects to this request as unreasonably burdensome and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

Please refer to Attachment OPUC 41 -1 for a summary of the invoices from The Brattle Group for 2015 related to the testimony from the outside expert (Frank Graves) in Oregon TAM docket UE 296. There were no invoices related to Oregon TAM dockets in 2014 or 2016.

(c) PacifiCorp objects to this request as unreasonably burdensome and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

Please refer to Attachment OPUC 41 –2.

OPUC Data Request 42

Please refer to PAC/400 Wilding/30 at lines 9 to 10. Please provide all analysis performed by PacifiCorp prior to performing economic shutdowns of coal plants. Please provide such data separately for each economic shutdown performed in 2016 and 2017.

Response to OPUC Data Request 42

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. Please refer to Confidential Attachment OPUC 42. PacifiCorp does not maintain records regarding operational issues analyzed for these decisions in the ordinary course of business.

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 43

Please refer to PAC/400 Wilding/32 at lines 9 through 13.

(a) Please explain participation in the energy imbalance market impacts PacifiCorp's decision to perform economic shutdowns.

(b) Please explain the reliability reasons that PacifiCorp prefers to not have more than one Jim Bridger unit offline at any one time.

(c) Please identify all other operational needs that affect PacifiCorp's decision to perform economic shutdowns of coal plants.

Response to OPUC Data Request 43

(a) If the opportunity to economically shut down coal exists, California Independent System Operator (CAISO) energy imbalance market (EIM) participation is considered when the Company determines which coal unit(s) will be shut down. If an EIM participating coal unit is shut down, it could potentially limit the EIM benefits the Company would otherwise be able to realize.

(b) The Jim Bridger units provide a substantial amount of operational flexibility to the entire Company system. The Jim Bridger units have the ability to provide regulating reserve to both the east and west balancing authority areas (BAA). In 2016, the Jim Bridger units and two other coal units held nearly 80 percent of the regulation reserve on the system. The Jim Bridger units are also the primary supply of frequency responsive reserves for the PacifiCorp West (PACW) BAA. With one or two Jim Bridger units offline, the system planning for single outage contingency (N-1) and subsequent multiple outage contingency (N-x) are magnified. Given the wide range of operation level and an increasing number of the low priced renewable energy coming from the EIM market, the Jim Bridger units serve as main coal plants on the Company system to provide economical and reliable electricity and also balance load, meet operational requirements, and comply with North American Electric Reliability Corporation (NERC) regulation standards.

(c) Coal plant economic shutdown is a holistic decision process. In general, when a coal plant's costs are higher than the market price of electricity, it is uneconomical to operate. However, coal plants have distinguishing characteristics that can make them either more or less valuable than market transactions. First, coal plants can provide additional value by carrying reserves to compensate for changes in load or generating resource output. Second, coal plants have some constraints such as startup costs, minimum up time, and minimum down time that can constrain how they are dispatched, and generally reduce their value relative to market. Coal plan economic shutdown is also dependent upon multiple variables including but not limited to, system load, coal and gas operation limitations (heat rate, fuel prices, ramp rate, up/down times, outage, etc.), hydro and wind generation, contractual position, market prices, EIM market condition and firm transmission constraints.

OPUC Data Request 44

Please provide all work papers, models and programs used by PacifiCorp to shape or generate the GRID input files. Please include any documentation available for work papers, models, and programs.

Response to OPUC Data Request 44

Please refer to Confidential Attachment OPUC 44, which provides PacifiCorp's Generation and Regulation Initiative Decision Tool (GRID) conversion wizard, which is utilized to convert Microsoft Excel data files into GRID input file format.

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 49

Please describe the current status and history of the Joy Longwall miner used at the Bridger Coal Company.

Response to OPUC Data Request 49

The Company objects to this request on the basis that it is overly broad and not likely to lead to admissible evidence relevant to this proceeding, as it requests information prior to the 2018 forecasted timeframe covered by this filing. Without waiving this objection, the Company responds as follows:

Bridger Coal Company (BCC) purchased the Joy longwall equipment, which had previously been used in the Deer Creek Mine. PacifiCorp sold the equipment to BCC at the appraised market value, and was also reimbursed by BCC for the cost of rebuilding the equipment and transporting it to BCC. The equipment was transferred in multiple shipments and was placed in-service on September 1, 2015, in the 14th Right panel. The Joy longwall operated successfully until it lost advancement capabilities over a period of time, between December 23, 2015 and December 31, 2015, due to adverse geological conditions. Following various unsuccessful attempts to restore the operation of the equipment, the Joy longwall was abandoned on October 7, 2016, as the equipment could no longer be safely restored to operation. Entries to record the PacifiCorp share of the attempted recovery and abandonment costs were reflected on the third quarter financial statements.

OPUC Data Request 50

Please provide the following information regarding the Joy Longwall Continuous miner used by Bridger Coal Company.

(a) Please explain the accounting treatment of the Joy Longwall miner.

(b) Please provide work papers documenting when and how the capital cost for the miner was expensed.

(c) For each year from 2015 to present explain how the expenses associated with the miner were incorporated into the coal costs charged by Bridger Coal Company to PacifiCorp.

Response to OPUC Data Request 50

The Company objects to this request on the basis that it is overly broad and not likely to lead to admissible evidence relevant to this proceeding. Costs associated with the Joy Longwall Mining System (Joy Longwall) are not included in the Company's 2018 net power costs forecast. Without waiving this objection, the Company responds as follows:

(a) The Joy Longwall consists of several major components assembled into a single mining system working simultaneously to extract coal on a continuous basis. The equipment was placed in-service as a capital asset on the books of Bridger Coal Company (BCC) on September 1, 2015. At the time of acquisition it was anticipated that all major components would have the same useful service life, thus the Joy Longwall was placed in the Property, Plant and Equipment account as one asset or system. It was then depreciated based on the "number of cycles" the system advances during a monthly reporting period. With each pass of the shearing machine (which extracts coal from the work face), the longwall system advances to maintain proper operating distance from the receding coal face. These system advances are known as cycles. The longwall shields/supports are designed to perform a specific number of cycle advances. The depreciation recorded becomes a component of the mine operating costs and is included in the cost of coal delivered to the Jim Bridger plant.

(b) Please refer to Confidential Attachment OPUC 50 for the BCC Capital Appropriation Document (CAD), which includes the economic analysis and supporting documentation relating to the BCC purchase of the Joy Longwall. Following the purchase of the Joy Longwall, depreciation costs are reflected in mine operating costs as described in Subpart (a) above.

(c) As described in Subpart (a) above, depreciation of the Joy Longwall system was recorded (utilizing a "number of cycles" basis) as mine operating costs, beginning September 2015. These costs were then included in the cost of coal delivered to PacifiCorp at the Jim Bridger Plant. Once the Joy Longwall lost advancement capabilities, only minimal depreciation costs were recorded as only a few cycle advances were possible during the recovery attempts. Consequently, the PacifiCorp two-thirds share of costs relating to the Joy Longwall impact only 2015 and 2016 as follows:

2015 – Depreciation Expense	$ 856,225
2016 – Depreciation Expense	$ 17,741
2016 – Attempted Recovery Costs	$ 7,551,394
2016 – Asset Abandonment	$12,560,956

There are no costs relating to the Joy Longwall in 2017.

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CASE: UE 323
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 502

Exhibits in Support
Of Rebuttal and Cross-Answering
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August 2, 2017

Staff Exhibit 502 is confidential and

Is subject to Protective Order No.16-128.

CASE: UE 323
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PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 503

Exhibits in Support
Of Rebuttal and Cross-Answering
Testimony

August 2, 2017

SYSTEM SIMULATION

[For B.E./B.Tech. and M. Tech. students of various branches of Engineering as well as B.B.A. and M.B.A. students of all Indian Universities]

D.S. HIRA
Director Shaheed Udham Singh
College of Engineering and Technology
Tangori (Mohali)
Punjab

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out and many assumptions have to be made, to maintain the neatness of the model and to meet the objectives of the study. To ensure that the behavior of the model is representative of the behavior of the real system, the assumptions have to be as close to reality as possible. If a theoretical probability distribution has been fitted to some observed data, and used as input to the simulation model, the adequacy of the fit should be tested by applying statistical tests. The output of a simulation model depends to a great extent on the assumptions made. For example, the assumptions about the probability distribution of the arrival pattern or service pattern, in a queueing system or of lead times and of customer arrivals in inventory system, have a great bearing on the model output results. Similarly, the through put rate of a manufacturing system is greatly influenced by the assumptions about the failure and repair times. The assumptions about the variability in processing rates have a direct bearing on the amount of work-in-process inventory in an assembly or production line. The reliability of the data can be verified by consultations, with the experts, by performing statistical tests, and by carrying out sensitivity analysis using common random numbers.

9.3.3 *Output Data Validation*

The objective of any simulation model is to transform the inputs to the system into output measures of performance. The validation of this correspondence is very important. In each simulation model, there are some specific responses which are of interest to the modeler and the model is built to predict these responses with reasonable accuracy over a range of input conditions. When the values of the selected inputs match the inputs to the real system, then the outputs of the model should also match the outputs of the real system. This should hold true not only for one set of data, but over a range of data.

For this input-output validation, the modeler requires some historical data for the purpose of comparison. Thus, it is almost necessary that some version of the system under study is available for data collection. It may be a true version of the system being modeled or some variant which can be modified to represent the system under study. In case a near variant of the proposed system is available, the simulation model of the existing near variant system is developed and validated. Then this model is suitably modified to represent the proposed system. The greater the commonality between the existing and proposed systems, easier it will be to build a truly representative simulation of the proposed system, and the greater our confidence in the model.

If the system being simulated is imaginary or at a planning stage, and no identical or near identical system is available for comparison, complete input-output validation is not possible. In such cases, the analyst should try to find out if some subsystems of the system under study are available. The partial validation can then be carried out. An animation of the simulated system may be helpful in evaluating the validity of the model.

9.4 Input-Output Validation – Using a Turning Test

This is a subjective type of input-output validation test. This may be performed in addition to the statistical tests or when no statistical test is applicable. In this test the knowledgeable persons are asked to identity the simulated data, when a number of sets of data generated by simulation are mixed with the sets of data obtained on real system. For example, suppose five reports of system performance over five different days are prepared by actual observation of a banking system. Also five reports, in identical formats, are generated by employing the simulation model. These ten reports are thoroughly shuffled and given to an expert for identification. If the expert succeeds in identifying a substantial number of reports, the model is not valid. The observations of the expert can then be used to further improve the model. On the other hand, if the expert cannot distinguish the simulated data from the real, the model is considered to be valid. This type of validation test is called a *Turning Test*.

CASE: UE 323
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 504

Exhibits in Support Of Rebuttal and Cross-Answering Testimony

August 2, 2017

Table 7a. Natural Gas Price, Electric Power Sector, Actual vs. Projected

Projected Price in Constant Dollars

(constant dollars per million Btu in "dollar year" specific to each AEO)

	AEO $ Year	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
AEO 1994	1992	2.44	2.48	2.57	2.66	2.70	2.79	2.84	2.92	3.04	3.16	3.25	3.36	3.51	3.60	3.77	3.91	3.97	4.08			
AEO 1995	1993		2.39	2.48	2.42	2.45	2.45	2.53	2.59	2.78	2.91	3.10	3.24	3.38	3.47	3.53	3.61	3.68	3.73			
AEO 1996	1994			2.04	2.10	2.05	2.18	2.19	2.19	2.21	2.22	2.23	2.24	2.26	2.26	2.30	2.33	2.40	2.44	2.53	2.63	2.71
AEO 1997	1995				2.42	2.18	2.18	2.19	2.19	2.19	2.22	2.25	2.27	2.28	2.29	2.31	2.33	2.34	2.32	2.34	2.36	2.37
AEO 1998	1996					2.67	2.43	2.43	2.48	2.53	2.55	2.55	2.60	2.63	2.68	2.73	2.77	2.81	2.84	2.89	2.90	2.93
AEO 1999	1997						2.42	2.60	2.62	2.67	2.74	2.80	2.87	2.94	3.00	3.03	3.04	3.06	3.08	3.10	3.11	3.12
AEO 2000	1998							2.48	2.59	2.59	2.62	2.65	2.72	2.79	2.88	2.95	3.01	3.05	3.08	3.11	3.14	3.16
AEO 2001	1999								3.90	3.79	3.27	2.99	2.88	2.88	2.91	2.93	2.96	2.99	3.03	3.06	3.09	3.14
AEO 2002	2000									4.39	2.59	2.92	3.12	3.19	3.22	3.26	3.31	3.34	3.38	3.46	3.52	3.57
AEO 2003	2001										3.07	3.42	3.29	3.27	3.24	3.32	3.48	3.62	3.79	3.88	3.98	4.04
AEO 2004	2002											5.62	4.50	4.18	4.10	4.14	4.23	4.11	4.04	4.19	4.36	4.54
AEO 2005	2003												5.98	5.92	5.27	4.83	4.50	4.39	4.27	4.31	4.41	4.54
AEO 2006	2004													8.09	7.24	6.54	6.22	5.77	5.46	5.26	5.24	5.36
AEO 2007	2005														6.97	7.12	7.07	6.53	6.22	5.83	5.69	5.50
AEO 2008	2006															6.90	7.24	7.40	6.96	6.65	6.49	6.25
AEO 2009	2007																8.87	4.56	5.13	5.45	5.52	5.54
AEO 2010	2008																	4.14	4.85	5.82	6.17	5.94
AEO 2011	2009																		5.07	4.72	4.65	4.64
AEO 2012	2010																			4.66	4.35	4.42
AEO 2013	2011																				3.32	3.72
AEO 2014	2012																					4.32
Actual in Nominal$		2.61	2.28	2.02	2.69	2.78	2.40	2.62	4.38	4.61	3.68	5.57	6.11	8.47	7.11	7.31	9.26	4.93	5.27	4.89	3.54	4.49
Average Absolute Difference		0.11	0.23	0.43	0.25	0.29	0.20	0.20	1.36	1.29	0.62	1.96	2.14	3.67	2.32	2.15	3.37	0.90	0.81	0.74	1.43	0.99

Projected vs. Actual

(percent difference)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
AEO 1994	-4.3	13.7	35.8	7.5	7.4	29.9	23.0	-22.6	-21.7	3.5	-28.3	-30.6	-46.0	-32.0	-28.9	-40.6	14.1	11.0			
AEO 1995		7.1	28.0	-4.5	-4.8	11.4	7.0	-33.0	-30.1	-6.9	-33.2	-34.6	-49.2	-36.0	-34.9	-46.4	3.3	-0.8			
AEO 1996			3.2	-19.0	-21.9	-2.8	-9.4	-44.5	-45.6	-30.5	-53.0	-55.7	-66.8	-59.1	-58.5	-66.1	-34.2	-36.5	-27.5	5.8	-12.8
AEO 1997				-8.4	-18.7	-4.9	-11.3	-45.7	-47.3	-32.0	-53.5	-56.0	-67.1	-59.5	-59.1	-66.9	-37.0	-40.7	-34.3	-6.8	-25.1
AEO 1998					-2.4	4.2	-3.1	-39.5	-40.0	-23.1	-48.1	-50.6	-62.8	-53.5	-52.6	-61.2	-25.6	-28.8	-20.5	12.5	-9.3
AEO 1999						1.9	2.0	-37.1	-37.7	-18.8	-44.1	-46.4	-59.1	-48.8	-48.3	-58.2	-20.5	-24.2	-16.1	18.3	-5.1
AEO 2000							-3.8	-38.5	-40.4	-23.3	-47.8	-49.7	-61.6	-51.3	-50.1	-59.1	-21.6	-25.1	-16.8	18.1	-4.7
AEO 2001								-8.8	-13.9	-5.5	-41.8	-47.6	-60.9	-51.5	-51.3	-60.3	-24.2	-27.4	-19.3	14.8	-6.8
AEO 2002									-2.6	-26.9	-44.4	-44.4	-57.6	-47.5	-47.0	-56.6	-17.2	-20.7	-10.7	27.8	3.7
AEO 2003										-15.2	-36.5	-42.7	-57.6	-48.5	-47.3	-55.4	-12.4	-13.1	-2.2	41.1	14.6
AEO 2004											3.0	-22.8	-46.6	-35.7	-35.2	-46.6	-1.9	-8.7	4.1	52.4	27.0
AEO 2005												0.6	-25.9	-19.0	-25.8	-44.4	2.6	-5.4	4.9	51.2	24.4
AEO 2006													-1.4	8.4	-2.2	-25.1	31.4	17.7	24.8	74.8	42.9
AEO 2007														1.1	3.0	-17.7	43.9	29.9	33.9	83.8	42.1
AEO 2008															-3.1	-18.1	58.3	41.1	48.3	103.3	56.6
AEO 2009																-2.3	-5.1	1.2	18.4	68.4	35.3
AEO 2010																	-15.5	-6.2	23.9	84.7	42.3
AEO 2011																		-2.6	-0.3	38.1	10.3
AEO 2012																			-2.6	27.8	3.9
AEO 2013																				-4.5	-14.5
AEO 2014																					-2.3
Average Absolute Percent Difference	4.3	10.4	22.3	9.8	11.0	9.2	8.5	33.7	31.1	18.6	39.4	40.1	51.0	39.4	36.5	45.3	21.7	18.9	18.2	42.9	21.2

Sources: Projections: *Annual Energy Outlook*, Reference Case Projections, Various Editions.

Historical Data: U.S. Energy Information Administration, September 2014 Monthly Energy Review, DOE/EIA-0035(2013/08) (Washington, DC, September 25, 2014), Table 9.10. Bureau of Economic Analysis, US Dept. of Commerce, September 2014.

CASE: UE 323
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
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OREGON

STAFF EXHIBIT 505

Exhibits in Support
Of Rebuttal and Cross-Answering
Testimony

August 2, 2017

Staff Exhibit 505 is confidential and

Is subject to Protective Order No.16-128.

CASE: UE 323
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 506

Exhibits in Support
Of Rebuttal and Cross-Answering
Testimony

August 2, 2017

Staff Exhibit 506 is confidential and

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CASE: UE 323
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Rebuttal and Cross-Answering Testimony

<u>REDACTED</u>
August 2, 2017

Q. Please state your name, occupation, and business address.

A. My name is Rose Anderson. I am a Utility Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. I provided reply testimony to PacifiCorp's initial filing in Exhibit Staff/300.

Q. What is the purpose of your response testimony?

A. I discuss REC credits for direct access customers and forecast accuracy of new Qualifying Facilities.

Q. Did you prepare an exhibit for this filing?

A. I have no exhibits connected to my Rebuttal and Cross-Answering Testimony.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: VALUE OF FREED-UP RENEWABLE ENERGY CERTIFICATES

Q. Please summarize the Renewable Energy Certificate (REC) valuation issue.

A. First raised in UE 296, the freed-up REC issue began when Calpine, then Noble Solutions LLC, argued that its customers were paying twice for RPS compliance because their Electric Service Provider (ESS) and PacifiCorp both charged them for the cost of complying with RPS standards. Direct Access customers are subject to a transition charge or credit, which is designed to leave other remaining customers harmless when the customer departs PacifiCorp's system—the goal being to leave cost of service customers indifferent to the departing load. There has been general agreement among the parties, after a series of workshops following UE 307, that RECs in PacifiCorp's possession that are no longer needed to be retired due to the loss of direct access load and hence, are freed-up RECs, do provide a benefit to PacifiCorp when a direct access customer departs.

Q. Is PacifiCorp disputing the concept that there is a freed-up REC that has value and therefore should be recognized when a direct access load departs?

A. For the first time in a power cost proceeding, PacifiCorp has proposed a methodology to transfer value to the customer.

However, the freed-up REC issue in this case centers on the question of the value of the freed-up REC and *how* to transfer the stranded benefit of freed-up RECs to the departing customer. In UE 296 Calpine proposed that

PacifiCorp should provide a credit in the transition adjustment to direct access customers based on the current value of RECs freed-up by their departure. In UE 307, Calpine stated that an alternative could be for PacifiCorp to transfer the RECs to the ESS, or else retire RECs on behalf of the ESS.

Q. What has the Commission directed regarding REC valuation?

A. After rejecting Calpine's argument in the 2016 TAM, the Commission noted in the 2017 TAM that there may be benefits to remaining cost of service customers due to changing the point in time at which PacifiCorp would need to take resource action to comply with the Oregon RPS. The Commission directed the parties to meet and discuss REC valuation in workshops.[1] The parties met accordingly and discussed potential methods of REC valuation but did not agree on a valuation method.[2]

Q. Have other parties raised this issue in the 2018 TAM?

A. PacifiCorp, in opening testimony, and Calpine in reply testimony, testified about potential methods to return the value of freed-up RECs to departing direct access customers.

Q. What solution was proposed by PacifiCorp in its Initial Filing to the 2018 TAM?

A. In PacifiCorp's initial filing to UE 323, it proposed to value RECs by using recent REC purchase prices from its 2016 RFP as a forecast of future REC

[1] Order No. 16-482. Page 22.
[2] PacifiCorp UE 323 Initial Testimony. PAC/100, Wilding/31.

prices, and then discount their value to present dollars from 2028, the estimated date at which PacifiCorp will need to take RPS compliance action based on its current supply of RECs.[3]

Q. What argument was made by Calpine in its Opening Testimony?

A. Calpine disagreed with PacifiCorp's proposed method, arguing that PacifiCorp's approach was inadequate and unfairly disadvantaged direct access customers.[4] Calpine proposed crediting Schedule 293, 295, and 296 customers based on the price of RECs recently sold by PacifiCorp or RECs purchased through the Company's 2016 Request for Proposals (RFP), using the full REC value as a credit without discounting it from future dollars to present dollars.[5] Alternatively, Calpine suggested PacifiCorp transfer RECs to the direct access customer's ESS or retire RECs on behalf of the direct access customer or its ESS. Calpine argued that this method would entirely avoid the REC valuation disagreement between parties.[6]

Q. What is PacifiCorp's response to Calpine in its Reply Testimony?

A. PacifiCorp argues that Calpine's recommendation to use current REC prices is contrary to the Commission's finding in the 2017 TAM of "little or no benefit from a reduction in RPS obligations due to the loss of load from direct access."[7] The Company argues that calculating the REC credit based on current REC prices would result in "impermissible cost-shifting," and states that

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[3] PAC/100, Wilding/32-34.
[4] Calpine Solutions/100, Higgins/4.
[5] Calpine Solutions/100, Higgins/4 at 12-15.
[6] Calpine Solutions/100, Higgins/4 at 16-23 and Higgins/4 at 1.
[7] PAC/400, Wilding/52 at 9-12, referring to Order 16-482.

remaining cost of service customers are not harmed by its use of a discounted future REC value.[8] The Company states that its proposal correctly bases the REC credit on the future delay in the Company's RPS compliance action, in alignment with the stranded benefit identified by the Commission in the 2017 TAM.[9] The Company also expresses concern about the potential administrative burden of transferring RECs and the potential liability associated with demonstrating RPS compliance on behalf of the ESS.[10]

Q. In summary, what are the three main options discussed by the parties for transferring the stranded benefit of RECs associated with a direct access customer's load from the Company to direct access customers?

A. One option is a credit to direct access customers, through the transition charge, based on an estimated value of RECs freed-up when the customer departs. There is not consensus among the parties for a method of valuing the RECs under this option. Staff also notes that cost-of-service customers would bear the risk of any REC price forecast error.

Another option is a transfer of RECs directly from PacifiCorp to an ESS. This option would transfer the value of freed-up RECs while avoiding the REC valuation dispute and minimizing risk from REC price forecast uncertainty. However, PacifiCorp has stated this method would create an administrative burden. It is currently not clear to Staff why choosing RECs

[8] PAC/400, Wilding/52.
[9] PAC/400, Wilding/52 at 7 – 15.
[10] PAC/400, Wilding/52 at 15 – 20.

for this purpose would be significantly more burdensome than the normal process of retiring RECs to meet the RPS compliance requirement of the Company's cost of service customers.

Finally, RECs could be retired on behalf of the ESS. This method would also avoid the REC valuation dispute and minimize risks due to REC price forecast error, but PacifiCorp has expressed concern about assuming liability for demonstrating RPS compliance on behalf of another party.[11]

The latter two options would transfer the freed-up REC value with precision. Using actual RECs would remove the stranded benefit without introducing the considerable uncertainty in REC price forecasts, thus preventing PacifiCorp from over- or under-charging cost of service customers for the value of RECs associated with departing direct access load.

Regardless of the value transfer method, the remedy should use the same number of RECs that would have been retired by PacifiCorp for a customer's load if that customer had not departed for direct access.

[11] PacifiCorp's Reply Testimony in UE 323. PAC/400, Wilding/54 at 8-9.

Q. Are there any unresolved questions about the REC valuation options?

A. There are several legal and policy questions implicated in REC credit valuation, direct transfer, and retirement of RECs on behalf of the customer or ESS. For example, the potential for PacifiCorp to retire RECs on behalf of an ESS depends on the interpretation of Oregon RPS statutes and whether the Commission supports this type of transaction.

Additionally, as PacifiCorp's testimony demonstrates, the long-term potential to resolve the stranded benefit issue with a transfer of RECs from PacifiCorp to an ESS depends on whether bundled RECs could be transferred to an ESS to meet the bundled REC portion of future RPS standards. These questions merit further investigation.

Q. What does Staff recommend the Commission do in order to thoroughly resolve any unanswered questions about the appropriate valuation of freed-up RECs?

A. Staff recommends that the Commission address a long-term solution in the currently open rule-making docket, AR 610, in which it could thoroughly consider potential methods for valuing freed-up RECs, transferring RECs, or retiring RECs on behalf of an ESS. This docket would provide an opportunity to discuss the issue in more detail than is possible in a power cost filing, and to develop a methodology to apply uniformly to all utilities going forward.

Q. What does Staff recommend regarding REC value transfer in the 2018 TAM?

A. Creating a fair method of transferring REC stranded benefits that causes no harm to cost-of-service customers is a worthy goal. However, it is a task best addressed in a rule-making docket outside of PacifiCorp's power cost filing. In the 2018 TAM, on a non-precedential basis, Staff would be supportive of using PacifiCorp's estimate of REC value from its initial filing, with the understanding that this is likely not the method supported by Staff going forward. It is, instead, a conservative valuation that could serve as a placeholder until the questions surrounding REC valuation, transfer, or retirement can be resolved.

ISSUE 2: QUALIFYING FACILITIES

Q. Please summarize the issue regarding Qualifying Facilities (QF) raised in the 2018 TAM.

A. In CUB's opening testimony, it raises the issue of QFs expected to come online after the final update to the 2018 TAM.[12] CUB points out that the Company's method of predicting the Commercial Online Date (COD) of new QFs has historically resulted in rates that include QF costs for non-operational QFs.[13] CUB proposed either derating the new QF MWh forecast based on a three year rolling average of days new QFs have been delayed, or creating an annual QF deferral.[14]

Q. Have any other parties raised this issue in the 2018 TAM?

A. Yes, Staff also raised the issue of new QF delays. Staff demonstrated the frequency of new QF COD delays in the 2017 TAM, and suggested an adjustment to the method of forecasting new QFs based on historical COD delays.[15]

Q. Has this issue been raised in past TAM filings?

A. Yes. In the 2017 TAM, UE 307, CUB's opening testimony raised the same issue and proposed disallowing contracts not yet in effect at the time of the final TAM update.[16] In its UE 307 rebuttal/cross answering testimony, CUB modified its recommendation to derate the QF forecast based on a comparison

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[12] CUB/100, Jenks 6.
[13]. CUB/100, Jenks 6-7.
[14] CUB/100, Jenks 10-11.
[15] Staff/300, Anderson 6-7.
[16] CUB/100, McGovern/21,24.

of forecasted and actual energy from new QFs in each of the most recent 3 years with complete data.[17] Staff raised the issue as well, recommending a similar adjustment based on historical delays.[18]

Q. What was PacifiCorp's response regarding this issue in the 2017 TAM filing?

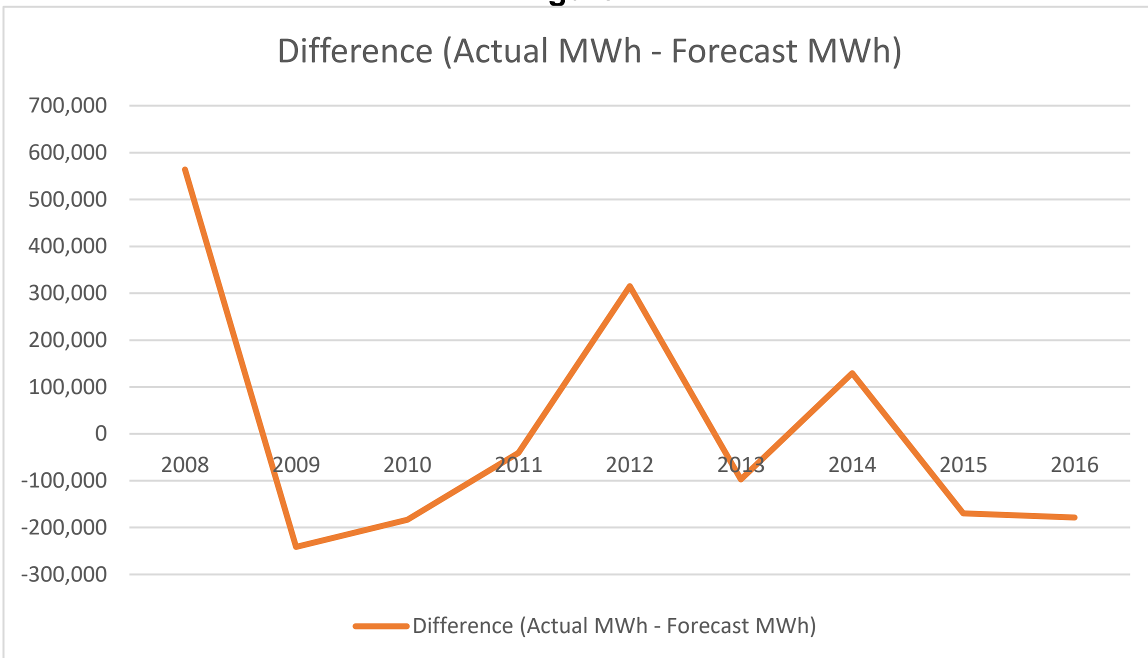
A. In PacifiCorp's UE 307 reply testimony, it argued that CUB had not shown why the QF provisions agreed to by parties in the 2015 TAM, docket UE 287, were insufficient.[19] The Company noted that the QF provisions include an "attestation" in which the Company affirms that it has a "commercially reasonable good faith belief that the new QFs will reach commercial operation during the rate effective period."[20] The Company also argued that CUB's recommendation disallowed timely recovery of QF contract costs, undermining PURPA's policy of cost recovery for QFs.[21]

Q. What new data is available in the current TAM, and what does it demonstrate about new QFs in PacifiCorp's power cost forecasting?

A. The data provided by the Company in reply testimony demonstrate a trend toward over-forecasting QF generation in recent years.

[17] CUB/200, McGovern/31 at 20-23.
[18].Staff/300, Crider/18-19.
[19].PAC/400, Dickman/85-86.
[20] PAC/400, Dickman/85 at 14-18, referencing Order No. 14-331 at 5.
[21] PAC/400, Dickman/89, at 3-4.

Figure 1



Over-forecasting generation from new QFs contributes to the trend of over-forecasting total QF expenses shown in Figure 1 above. New QFs predicted to begin operation after the final update to the TAM have been a not-insignificant portion of total QF costs in recent TAM filings. Improving the accuracy of new-QF forecasting will bring the QF forecast portion of the TAM into greater alignment with actual experience, in which less than 100% of forecasted new QFs come online within the power cost year.

Q. What does Staff recommend to improve the accuracy of new QF forecasting in PacifiCorp's TAM?

A. Staff recommends using an average delay based on the last three years of QF expected Commercial Operation Dates in the TAM. The forecasted COD of each QF would move forward by the resulting average of delay days, weighted by the MW capacity of the QF. The result of adjusting the COD of new QFs in the TAM based on historical delays will be a more realistic QF forecasting method than the current practice of assuming no new QF will experience a delayed COD. In the 2018 TAM this method will likely result in Staff's previously suggested adjustment of **[BEGIN CONFIDENTIAL]** $[redacted], **[END CONFIDENTIAL]** depending on upcoming TAM updates.[22]

In UE 323, CUB has suggested, as one possibility, a deferral of new-QF costs in the TAM.[23] Staff does not recommend using a deferral to true-up QF expenses. A deferral within the power cost filing, itself already a deferral, is unnecessarily complicated and amounts to single-issue ratemaking. Staff's proposal is sufficient to improve forecast accuracy, resulting in fair and reasonable rates.

Q. Does this conclude your testimony?

A. Yes.

[22] Confidential Workpapers of Michael G. Wilding, "ORTAM18 NPC Study CONF_2017 03 21."
[23] CUB/100, Jenks/11.