BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 307

In the Matter of PACIFICORP, dba)
PACIFIC POWER,)
2017 Transition Adjustment Mechanism)

OPENING TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

July 8, 2016

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 307

In the Matter of PACIFICORP, dba PACIFIC POWER, 2017 Transition Adjustment Mechanism	OPENING TESTIMONY OF THE CITIZENS' UTILITY BOARD OF OREGON

My name is Jaime McGovern, and my qualifications are listed in CUB Exhibit 101.

I. Introduction

On April 1, 2016, PacifiCorp ("the Company" or "PAC") filed the 2017 Transition Adjustment Mechanism ("TAM"). The Company requests, from Oregon customers, $379.2 million in power costs for 2017, an increase of $7 million over the 2016 TAM and an increase to Oregon rates of $19.9 million.[1] This is in contrast with Portland General Electric's reduction in net variable power costs ("NVPC") for 2017. PacifiCorp's forecasted NVPC increases for several reasons. The Company presents the major drivers as it sees them:[2]

[1] UE 307 PAC/100/Dickman/3.
[2] UE 307 PAC/100/Dickman/9.

Table 1
Net Power Cost Reconciliation

	($ millions)	$/MWh
OR TAM 2016	**$1,521**	**$24.94**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	$46	
Purchased Power Expense	$7	
Coal Fuel Expense	$48	
Natural Gas Fuel Expense	($55)	
Wheeling and Other Expense	($2)	
Total Increase/(Decrease) to NPC	**$45**	
OR TAM 2017	**$1,566**	**$25.86**

CUB addresses its concerns with some of these components, along with additional concerns about the filing, including coal costs, forecasted EIM benefits, modeling changes to the NVPC, and the difficulty of obtaining usable information in a timely manner throughout the pendency of this case.

II. CUB's Issues

A. Coal Costs and Coal Plant Costs

Coal fuel expense is 48 million dollars higher than in the 2016 TAM. There are several reasons for this[3]. In general, many of the Company's coal plants are operating differently than they were when they were built, no longer the most economical baseload resource in the stack. Instead, often being operated as a marginal or peaker unit. However, the Company has recently signed new coal contracts for several of these plants, chaining ratepayer dollars to inefficient and

[3] UE 307 PAC/100/Dickman/9.

environmentally risky resources years into the future. Since 2013, the Company has signed new coal contracts for Huntington, Jim Bridger, Dave Johnston and Naughton[4].

i. JIM BRIDGER

The Company describes the change in coal costs as one of the main drivers behind the increased NVPC for 2017:

> [T]he increase in NPC is driven mainly by a reduction in wholesale sales revenue and an increase in coal fuel expense.[5]

Additionally, the Company cites the Bridger Coal mine as a major driver of coal mine cost increases for the 2017 TAM.[6] Coal fuel expense increased by $48.2 million in the 2017 TAM.[7] This is a 7% increase. Since overhead costs at coal mines are high, decreased production at the Bridger mine means a higher per unit cost for coal. Mr. Ralston states that Mr. Dickman provides clarity on these cost changes, specifically those at Jim Bridger:

> Mr. Dickman provides additional testimony describing the circumstances affecting coal generation in the TAM filings, including reductions in generation at the Jim Bridger plant.[8]

However, CUB was unable to find much detail about the situation at Bridger in Mr. Dickman's testimony. In his testimony, Bridger was only mentioned four times, once stating that average production costs were higher,[9] once discussing inter-regional EIM benefits,[10] and twice in this statement:

---

[4] *See* CUB EXHIBIT 102.
[5] UE 307/PAC 100/Dickman 9.
[6] UE 307/PAC 200/Ralston 12.
[7] UE 307/PAC 200/Ralston/3.
[8] UE 307/PAC 200/Ralston/14.
[9] UE 307/PAC 100/Dickman/10.
[10] UE 307/PAC 100/Dickman/28.

> The primary factor contributing to lower coal production and coal deliveries in the 2017 TAM is reduced generation at the Jim Bridger plant.[11]

For details, Mr. Dickman passes the baton to Mr. Ralston:

> Additional details regarding the cost of coal during the test year are provided in the direct testimony of Mr. Ralston.[12]

CUB finds the situation concerning for several reasons. Several key factors are changing. There are higher overall coal production costs at the Jim Bridger coal mines. There are higher average production costs at the Jim Bridger generation plant. The minimum operating levels increased at the Jim Bridger plant. The combined effect is to give Jim Bridger, an average MWh cost higher [redacted].[13]

These changes are all connected. Moreover, these changes are, in part, being driven by environmental upgrades installed by the Company on Jim Bridger 3 (and forecasted to be installed on Jim Bridger 4) and subsequently affecting operation:

> *Thermal Upgrades/Environmental Controls*—Environmental upgrades at Jim Bridger 3 in November 2015 resulted in an increased minimum operating level. Environmental upgrades will result in a similar impact to Jim Bridger 4 in November 2016.[14]

Another effect is the decreased production from each ton of coal, or inversely, the increased average cost per MWh, or in the case of Jim Bridger, an average [redacted]

---

[11] UE 307/PAC 200/Ralston/13.
[12] UE 307/PAC 100/Dickman/11.
[13] *See* CONF CUB EXHIBIT 103 row 990.
[14] UE 307/PAC 100/Dickman/12.
[15] *See* CONF CUB EXHIBIT 103 row 990.

For a better understanding of this issue, CUB asked the Company to clarify how these changes applied to Oregon customers, in light of the fact that the environmental retrofits were not approved for use in Oregon rates.

The Company responded non-informatively:

> The referenced changes in operating characteristics of the Company's existing thermal resources represent the best information available about the transition adjustment mechanism (TAM) forecast period and are thus appropriately included in the net power costs (NPC) forecasts.[16]

CUB therefore finds no basis to include the subsequent increased average costs, increased minimum operating level, and other related costs in Oregon rates. These retrofits have not been examined and found to be prudent. These SCR investments at Bridger were reviewed in LC 57 and the Commission declined acknowledgement for four reasons:

> Based upon the information we have at this time, we decline to acknowledge Action Item 8c related to Bridger Units 3 and 4 for four reasons. First, some of the modeled alternatives suggest that the installations of SCRs are not the lowest cost resource option. For example, as described on page 4 of Staffs Final Comments dated January 10, 2014, alternative D runs demonstrate that it is more economical to retire Bridger 3 and 4 than to install the SCR equipment. Based upon the information we currently have, we cannot dismiss these results as unrealistic or unreasonable.
>
> Second, we concur with Staff that there are gaps in PacifiCorp's analyses. As Staff notes, PacifiCorp did not consider the potential tradeoffs between units at Bridger 3 and 4 or between coal plants to identify the most cost effective compliance options from a state or fleet perspective. Additional analyses on these issues would have resulted in more information for us to make an informed decision on acknowledgment.
>
> Third, Staff and other participants have raised several other specific issues related to the merit or lack of merit of installing SCRs at Bridger 3 and 4, such as the impact of retirement on reliability, inter-temporal and fleet trade-off analysis between units, or the impact

[16] *See* CUB Exhibit 104.

> of retirement on future transmission investments. However, we lack the necessary information in this proceeding to weigh these issues and they will be more thoroughly investigated in a future rate case proceeding.
>
> Finally, PacifiCorp is going ahead with the investments in installing SCRs regardless of our decision in this proceeding. We will undertake a thorough and fair review of the prudence of PacifiCorp's decision in a future rate case proceeding.[17]

While the Commission promised a through and fair review of this investment, that review has not been undertaken because PacifiCorp has not filed a General Rate Case to add the capital costs of the SCRs to its rate base, which typically would trigger a prudence review. But this investment in SCRs is causing higher rates to customers though this proceeding.

In LC 57, CUB argued that PacifiCorp's modeling of the Bridger SCRs was flawed, that PacifiCorp misapplied the EPA's cost-effectiveness limit and modeled the wrong years when considering phasing out the units as alternative to investing in SCRs.[18] CUB recommended that the Commission not acknowledge the investments.

For the same reasons that CUB recommended non-acknowledgement in the IRP, CUB would likely have recommended that the Commission find these investments imprudent in a General Rate Case. Typically, a finding of imprudence requires removing the financial harm of that imprudence to customers.

---

[17] *In re PacifiCorp dba Pacific Power 2013 Integrated Resource Plan,* OPUC Docket No. LC 57, Order No. 14-252 (July 8, 2014) at 8, 9.

[18] LC 57 Opening Comments of the Citizens' Utility Board of Oregon, pages 12-20.

a. CUB Recommendation:

These SCR investments have not been found to be prudently incurred. In addition, without an IRP acknowledgement, these investments should not be given any presumption of prudence. Therefore, the higher coal costs associated with the additions of the SCRs at Bridger 3 and 4 should be denied. CUB Confidential Exhibit (CUB Exhibit 105) shows that this will reduce NPC by [redacted][19, 20]

ii. NEW COAL CONTRACTS

CUB has reviewed the Company's highly confidential coal contracts and coal transport contracts. Many of the contracts were signed years ago when a coal plant was envisioned as a baseload plant. Therefore, it is understandable that the change in the gas economics and renewable economics may make some of the legacy agreements non-economical in retrospect. As such, CUB does not take issue with customers incurring coal costs of older contacts if the plants are being operated and the fuel is being sourced in the most economical way possible.

However, just two years ago[21] the Company signed several large coal agreements after the 2013 IRP, and after parties argued on the record that the Company needed to consider regional haze (a form of environmental risk) in its planning. CUB finds an expensive and binding commitment to coal in the current environmental, federal, and regulatory atmosphere imprudent.

---

[19] *See* CONF CUB Exhibit 105.

[20] The Company, in the modeling, did not reflect all impacts of the SCR. These additional impacts could have the effect of increasing the adjustment.

[21] *See* CUB exhibit 102.

In addition, CUB does not believe that the customers should be forced to take, on face value, that their only two options concerning their coal plants are to: (1) take coal at the minimum take or (2) pay for the coal regardless of whether the Company can use it or not.

Also, CUB is concerned about the sheer number of the Company's coal plants--which were intended as baseload plants—that are running at or near their minimum operating levels, and being treated more as peaking/cycling units. There are concerns of damage, and long term costs, that customers should not bear if the Company is operating the plants in an adverse way. Cycling the plant more often may be more economical in the short run, but there is evidence that this approach drastically increases forced outage rates and damage down the road[22]. The Company needs to be comprehensive and transparent in its approach of the coal supply and the coal plants.

The Company should explore other options. One such option on which CUB sought wisdom was the concept of reselling the coal, possibly at a reduced price, in the market to reduce the bleeding. The Company refused to explore or model this possibility.[23] CUB feels that there are possibly other options as well, including changes in stockpile levels. Some of the plants which are triggering the take or pay lever in the 2017 TAM (and some which may trigger this lever in the update, if gas prices continue to fall) may be more economical in the following year. Coal fuel expense increased this year by $48 million dollars. Customers are spared the full impact of this because of the savings from low natural gas costs, a

---

[22] http://www.nrel.gov/docs/fy14osti/60575.pdf
[23] *See* CUB exhibit 106.

reduction of $55 million from the 2016 TAM[24]. However, gas prices may not always be low. If the Company explored options for stockpiling coal that they are forced to take-or-pay, it could be used when gas prices increase, acting as a gas-hedge, insulating customers against rate volatility.

Currently, the Company charges the full cost of the take-or-pay provision to this year's TAM without any economical consideration for the options

CUB also reads many of the contracts to allow the Company release from the coal contract if the Company is unable to obtain the necessary permits, or more generally, Force Majeure is triggered regulation renders the plant inoperable. Environmental regulation may have this effect. CUB is researching this issue.

One of the reasons for this cost increase is higher costs due to take or pay coal contracts that require the Company to purchase coal beyond its needs.

CUB Recommendation:

CUB recommends that the Company be allowed to recover the costs associated with take or pay provisions from the older contracts because the Company may not have been fully aware of the implications of regional haze rules at the time those contracts were signed. However, CUB believes that the costs and impacts of the most recent take or pay contracts should be disallowed.

---

[24] UE 307 PAC/100/Dickman/9.

B. EIM Costs/Benefits

i. INTRA-REGIONAL BENEFITS

The Company forecasts 2017 EIM benefits to its customers at a much lower level than what the CAISO reports for 2015 or 2016. This is confusing, especially given the entrance of new participants into the EIM, which bring benefits, and the expectation of more entrants, including PGE. CUB asked the Company to clarify this apparent mismatch, and to reconcile the Company's 2017 benefit forecast of $6.4 million[25], against CAISO's estimate of $33.26 million[26] in PAC benefits for the most recently available four quarters. The Company responds by stating that CAISO's calculation of benefits includes three categories of benefits:

1. Inter-regional dispatch;
2. Intra-regional dispatch; and
3. Flexibility reserves.[27]

The Company goes on to state that PAC does not include category 2 (intra-regional benefits), and does not feel inclusion is appropriate because the intra-regional benefit is a benefit that is generated from "more optimal dispatch" of the Company's own resources, relative to its pre-EIM "more manual dispatch process" used in actual operations.[28]

CUB understands this argument—that prior to EIM investments, and the subsequent more automated dispatch, the Company forecasted efficiencies and benefits in GRID that did not actually exist. If CAISO calculations are approximately accurate, these intra-regional benefits are approximately $28

[25] UE 307/PAC 100/Dickman/26.
[26]*See* CUB exhibit 107.
[27] *See* CUB exhibit 107.
[28] *See* CUB exhibit 107.

million. Now, with the increased automation that comes from the EIM investments, the Company is able to dispatch its system more similar to the efficient GRID dispatch. Therefore, adding intra-regional benefits to the forecast (that are already internalized by GRID) would be double counting.

However, CUB respectfully disagrees with this argument. First, the Company cited improved dispatch as a benefit of EIM entrance.

> By participating in the EIM, the Company's participating generation units are optimally dispatched using the CAISO's computerized security constrained economic dispatch model. The EIM's automated, expanded footprint, co-optimized dispatch replaces the Company's largely isolated and manual dispatch within its two BAAs. Participation in the EIM produces benefits to customers in the form of reduced NPC, partially offset by costs for initial start-up and ongoing operation.[29]

Moreover, the Company explains how this benefit is realized:

> Q: What is the primary change in the Company's day-to-day operations as a result of EIM?
>
> A. Before EIM operation, the Company manually dispatched most of its regulating resources to balance the system within the hour, generally via phone calls to plant personnel. As a result, requests would typically be sent to the fastest responding and most flexible units first, to ensure system balance and reliability was maintained. As the balance returned to normal, additional requests would be sent to dispatch up lower-cost units and dispatch down higher-cost units. This approach could result in dispatch of higher cost units than strictly necessary in a computer-optimized world. Under EIM, dispatch instructions are automatically sent to all participating resources every five minutes. This helps minimize costs by ensuring the lowest cost resources that are available are dispatched.[30]

CUB reads this to mean **system** balancing, not just CAISO balancing, and therefore the intra-regional benefit, from the EIM investment is realized within PAC. CUB's interpretation is further supported by PAC's explicit promise of benefits in the 2016 TAM, including optimized dispatch.

---

[29] UE 296/PAC/100 /Dickman/10.
[30] UE 296/PAC/100/Dickman/10-11.

> Participation in EIM is expected to reduce the Company's actual NPC in three ways: (1) optimizing the automated dispatch of participating units in PacifiCorp's BAAs, subject to transmission constraints, using the CAISO's system model...[31]

Additionally, in light of the fact that the very year that the Company both invested in and automated its system through EIM, it added a large surcharge to its NVPC in UE 296 which it called the Day-Ahead and Real-Time (DA-RT) System Balancing Transactions Adjustment. That surcharge was based on the argument that GRID was optimizing the system perfectly in each hour and that in real time, the Company was unable to perfectly optimize its system. The Company added an adjustment to rates that reflects the cost of real time balancing of its system. In other words, the Company removed the forecast bias that came from GRID optimizing the system perfectly in each hour. However, the Company is removing these EIM benefits because "GRID always assumed perfectly optimized hourly dispatch of PacifiCorp's generating units[32]."

The Day-Ahead and Real-Time System Balancing Transactions Adjustment is based on the actual market purchases and sales that the Company has made in the previous 3 or 4 years.[33] Last year, the Company took three years of pre-EIM data and imputed the implicit cost of manual dispatch into the model. Based on this data, the Company argued that GRID, because of its "perfect" modeling did not account for the real life inefficiencies. This adjustment for real-time

---

[31] UE 296/PAC/100/Dickman/12.

[32] *See* CUB Exhibit 107.

[33] It was three years in 2016 TAM, *see In re Pacific Power 2016 Transition Adjustment Mechanism*, Order No. 15-394, OPUC Docket No. UE 296 at 4; It is 4 years in the 2017 TAM, *see* UE 307/ PAC/100/Dickman/18-19.

balancing increased rates by $8 million.[34] This year the Company modeled 4 years of data (July, 2011 to June, 2015) and is proposing a $9.1 million addition to rates in order to remove this forecast bias[35].

CUB Recommendation:

CUB recommends that the PUC reject PacifiCorp's argument that we ignore the intra-regional benefits. That is intra-regional benefits are real benefits of EIM that need to flow to customers. The Company is incorrect in claiming that those benefits have already flowed through GRID to customers though GRID optimization logic. Because most of data used to justify the DA-RT adjustment is pre-EIM, customers neither receive the Intra-regional benefits from the EIM or the optimization benefits from GRID. Rather than double counting the benefits as the Company suggests it is trying to avoid, it has eliminated the benefits.

CUB recommends that the Company include the intra-regional benefits, and resolve and quantify any difference between CAISO estimation of benefits and their own. In addition, CUB recommends that the Commission consider an audit of PacifiCorp's EIM costs, benefits and accounting.

ii. ACTUALS DISCOUNTED FOR FORECASTING

CUB also finds that EIM benefits are forecasted to customers at a discount, which is inappropriate. One might think that, on the simplest level, net benefits from EIM participation that flow to customers can be calculated as benefits minus costs. On a deeper level, the Company benefits when it is able to procure energy for its customers at a lower cost than it can produce it in house. Benefit? Check. On the flip side, the Company is subject to fees from CAISO

[34] OPUC Order No. 15-394 at 2.
[35] UE 307/PAC/100/Dickman/18

participation. Cost? Check. So, in the calculation of net benefits from EIM participation, there are multiple components that go into the benefits column and multiple elements that go into the costs column. There is a distinction to be aware of: actual benefits that flow to the Company for a particular year, say 2016, compared to forecasted benefits which flow to customers. Customers do not get actual benefits that flow above the forecasted level, unless they are so significant that they trigger the PCAM deadband, and even then, they are subject to sharing. Therefore, getting the forecast right is important. Systematically diluting or reducing forecasted benefits is not benign in nature. All bias is not eliminated by a dollar for dollar true-up.

In a confidential response to OPUC Staff,[36] the Company provided a summary of actual benefits from EIM. CUB, after reviewing the responses regarding EIM calculations believes that the Company computes benefits in the following way:

The import benefits are calculated as:

$$Import\ Benefit = import\ avoided\ cost - import\ cost$$

The export benefit is calculated similarly:

$$Export\ Benefit = Export\ revenue - export\ cost$$

These two components are added to get the total benefit (this is reported on a monthly basis). However, the calculation seems to be dependent on another number, which is the Export MWh/[MidC to COB transmission], where [MidC to COB] is the transmission that PAC made available to CAISO for

[36] *See* CUB CONF Exhibit 108.

transfer[37]. If this number were 100%, it would mean that, in that period, PAC exports to the EIM utilize all available firm capacity that PAC made available to CAISO. If that number were 50%, PAC made available twice as much export capacity as CAISO dispatched from PAC's system. Or, put another way, PAC had enough transmission capacity to dispatch twice what it actually exported to CAISO. The data response provides this number on a monthly basis, but that monthly summary does not tell us how often PAC bumped up against its transmission constraints in exporting to EIM. Nor does it tell us how PAC calculated how much capacity to make available to CAISO EIM on a long-term basis, or what the strategy is. However, PAC uses this number (which, is by definition always below 1) as a discount factor in forecasting future year benefits. That is, PAC is using the transmission capacity that it makes available to CAISO as a forecast input for future year benefits. This approach has several problems.

First, the actual benefits that flow to the Company are not reflected in full. They are discounted by this historical transmission usage factor. Second, the actual MWh that were exported by PAC to EIM may have in fact been, in some periods, constrained by transmission. In that event, the lower number (lower of MW available for export vs export transmission capacity available) is already reflected in the actual MWh exported. To discount that by available transmission capacity would be double counting the impact of the transmission constraints. Third, the transmission that the Company plans and makes available to EIM and CAISO is an endogenous number, and is not well forecasted or transparently relayed by a trend-line. Usage of this discount factor for forecasted EIM benefits

[37] *See* CUB CONF Exhibit 108.

unnecessarily complicates the forecast and obfuscates verification and independent analysis. Fourth, this discounting methodology is not a practice the Company uses in sales-for-resale generally, California Oregon Border (COB) sales, or imports. The Company selectively and opportunistically employs this method for EIM specific exports.

CUB Recommendation:

CUB recommends that this discount factor not be included in the forecasting methodology.

iii. USING OPPORTUNITY COST AS COST BASIS LEADS TO A BENEFIT DISCOUNT

PacifiCorp also discounts forecasted sales by discounting the actual basis of the forecast--the actual exports. The general picture is the following. The Company has generation resources that are, at times, economical for dispatch beyond the needs of their own customers. When this is true, the Company has several options. First, and somewhat traditionally, the Company can contract sales-for-resale. They do this at the Mid-Columbia Market (Mid-C) and COB. The generation that the Company exports to the California Market, either through COB or EIM follows the same physical path, and requires the same transmission capacity. Therefore, they can be thought of as substitutes in revenue generation. The Company either commits power to COB in a signed contract, or it submits power to EIM which CAISO, at its economical discretion can dispatch from PAC. When the Company makes the decision to commit generation (and the corresponding transmission) to COB, it does so on the basis that the revenue of the sale at COB is higher than the expected value from withholding that power from COB and reserving it for the EIM. This decision may or may not turn out to be wise in retrospect. The Company may reserve power, failing to secure a COB contract, only to find that the revenue it receives from the CAISO EIM market is lower, or the power is not sold at all.

In its methodology for calculating benefits, the Company seems to subtract the difference between COB and EIM prices as a lost opportunity cost.[38] At first glance, this seems innocuous. However, several factors must be considered. When the Company decides to withhold power from COB in order to supply the EIM, it is inherently valuing the EIM option above COB. If the Company turns out to be wrong, customers should not be punished twice for this--once in actuals, and another in forecast. If the Company happens to be correct, and they make more money in the EIM than they would have at COB, there still should be no discount in benefits for opportunity cost for several reasons.

First, because of timing differences, it may not always be the case that the volume available for contract in the EIM market is available in the COB market. To the extent that there is a mismatch, using possible COB transaction as a cost basis for EIM benefits is misleading. To the extents that volumes in both markets are translatable, there are still substantive issues.

Second, if the Company continues to see more opportunity in the EIM market, withholding more and more power from COB, then, over time, this will be reflected in decreasing historical COB sales, and the forecasts of sales-for-resale will decrease in TAM forecasts as well. In addition, the sales volume in the Day-Ahead and Real-Time System Balancing Transactions Adjustment, which is based

[38] *See* CUB CONF Exhibit 109.

on actual sales volumes, will decline. Unless we ignore this trend in the data, we are double counting the shift in surplus generation from COB to EIM.

Third, customers pay, in rates, cost of generation, base rates and fuel costs, and variable costs. When deciding whether a resource is economical and prudent, and consequently, when costs are put into rates, opportunity costs of surplus generation is not a cost. The revenue that the Company receives should be netted against the costs that are paid for by customers-- the generation costs. In the case of NVPC, these are incremental costs of production.

Fourth, the way in which CAISO calculates the revenue to be paid to PacifiCorp for a transfer is the following. CAISO considers the market price where the power will be imported, and then takes the marginal resource cost where the power will be generated (submitted by PacifiCorp to CAISO), and takes the halfway point or average between the two. This midpoint is the amount that the Company receives for its power sale to CAISO EIM. CAISO does not take into account, or use as a cost basis, COB prices that the Company could have transacted in the day-ahead market. Therefore, if the market price in California is $50/MW, and PacifiCorp has a resource that can dispatch for a marginal cost of $30/MW, then CAISO pays the Company $40/MW. What if the Company had surpassed an opportunity to contract at COB for 36? Then customers would be out of the money, getting paid $40, but netting that against $36. Customers would gain $4 in this transaction, but would have gained $6 if the Company had contracted to sell at COB. Economically, the optimal outcome is to use the resource to displace the $50 CAISO, but this is not what is in the economic interest of customers. This treatment biases benefits downward for customers.

CUB Recommendation:

CUB recommends that the Company remove the opportunity cost adjustment from benefits calculation. It misaligns the interests of the customers and the Company. The Company must be dispatching its resources in the most economical way possible. But that is not enough, the Company should ensure that its customers are not harmed the accounting of this.

iv. GOT BENEFITS?

CUB is concerned from a very fundamental perspective that customers were misled into EIM entrance, and CUB is now very concerned about possible full integration of PacifiCorp into CAISO and the proposed Regional Transmission Organization. When PacifiCorp first approached parties with possible EIM entry, the Company's own study showed expected benefits above $25 million/year. The Company downplayed that, and got benefits passed through on an equal basis to costs for the first year. The following year, things improved slightly for customers:[39]

[39] TABLE 2 UE 296/PAC/100/Dickman/9.

Table 2
Total-Company EIM-Related Benefits and Costs

$ millions	**UE 287/UM 1689**	**2016 TAM**
Inter-regional dispatch	Not specified	$8.4
Intra-regional dispatch		N/A
Flexibility Reserves		$1.0
Within-hour dispatch		N/A
Test-period EIM benefits	**$6.7**	**$9.4**
Test-period EIM costs	**$6.7**	**$5.1**

However, it is clear there are still entire categories of benefits being ignored. CAISO estimates current benefits to PAC at over $30 million per year[40]. Yet PacifiCorp still denies the existence of the majority of these benefits, documenting how benefits are barely exceeding ongoing cost and proposing that net benefits are expected to remain trivial. CUB takes serious issue with this. Large amounts of capital and Company resources are beings spent on behalf of customers, and, almost two years in, the customers have yet to see the forecasted benefits. CUB also finds it suspicious that several other companies, including NV Energy and PGE are scrambling to join the EIM when they see such paltry benefits for them or their customers on the horizon. Or more likely, do they see large amount of dollars flowing into the Company and barely any of that needing to flow back to the customers because of the Commission's and parties' inability to decipher the company's convoluted accounting and inability to hold the company accountable.

[40] *See* CUB CONF Exhibit 107.

CUB Recommendation:

The PUC Staff should conduct an audit of EIM accounting practices, costs and benefits. The Company should pass through the full benefits of intra-regional benefits. The Company should remove the benefit discount from perceived opportunity cost and the CAISO transmission utilization factor.

C. Increased Purchased Power Costs -

i. CUB's Understanding

Qualifying Facilities ("QF") power is **the main** driver of higher purchased power costs. This is not pocket change. The Company admits there are an additional $99 million in QF purchases over the 2016 TAM forecast. Lower market prices are forecasted in 2017.[41] Market purchases in the 2016 TAM were included at an average price of "$27.23/MWh, while market purchases in the current case are included at an average price of $24.60/MWh, a 10 percent decrease.[42] However, customers will not realize the benefit of these low priced markets because of the QF contracts that the Company has forecasted into the 2017 TAM. CUB understands that the Company must accept QF contracts that are presented to it. However, CUB disagrees that this number, either number of contracts, or number of MWs contracted should be the forecasted number for the NVPC. In the 2015 TAM, only 80 of the 96 MW forecasted actually came online.[43] The next year, the forecasting error became drastically worse. In the 2016 TAM, PAC forecasted 1006.43 MW of solar, but only 80 MW is actually online

---

[41] UE 307/PAC/100/ Dickman/10.
[42] UE 307/PAC/100/Dickman/10.
[43] *See* CUB CONF Exhibit 110.

In fact, not a single one of the projects forecast for 2016 has come online.[44] The only solar QFs that were providing power to PAC customers were the ones that had gone into service the year before. In 2016, from a MW point of view, the Company over-forecasted by 12 times the actual power.[45] The actual power that PAC procured from QFs was 8 percent of what was forecasted. The Company may argue that all the 1000 MW of power will come online from the QFs by the end of the year. This does not resolve the issue, because, according to Exhibit 102[46], the Company forecasts the entire fleet of QFs available and serving customers from January 1, which means customers will pay the higher rates starting January 1, for resources that were not used and useful.

This inappropriate inclusion of QF priced power in NVPC is harmful to customers in a very direct way. QF power displaces lower cost market purchases which are declining in price. If it is forecast into rates, customers pay above market rates for that forecasted power. Then, when the QF power does not come online, the Company replaces that unmet need with either in house generation, or market purchases, both which are below QF prices. The Company is allowed to pocket the difference, and the customers are left overpaying for QF power they never received.

CUB recognizes that there are several issues at play and is concerned that the problem will continue to grow. The Company must sign any QF contract presented to it, at avoided cost rates. Once signed, the QF has three years to actually bring the power online. In that three year time lapse, the QF

[44] *See* CUB CONF Exhibit 110.
[45] *See* CUB CONF Exhibit 110.
[46] UE 307 PAC/100/Dickman/107.

experiences declining costs, and can bring the power to commercial operation at the last possible minute, all the while stating that it expects the facility to come online sooner, as a placeholder. There is really no disincentive to act in this way, since the QF only pays the Company for liquidated damages, upon non-performance in the case where the cost to replace the promised power is higher than the QF price. In the current world of declining costs for solar and low market prices, CUB believes that the problem will continue to increase. As potential QFs scramble to get contracts signed at high avoided costs with the expectation of decreasing avoided costs, the QF power under contract will continue to far outstrip those not under contract.

There is little evidence that all the forecasted QFs will be used and useful in 2017, let alone in January, which is when the Company has them all forecasted to be commercially operational. In the first six months of 2016, not a single one of the UE 296 forecasted QF solar facilities has come online. When asked how the Company formulates a forecast for QF deployment in the TAM effective year, it states:

> The Company determines the solar QF projects that are expected to achieve commercial operation during the forecast period based on the commercial operation date (COD) identified in the executed power purchase agreement (PPA), informed by continual discussions with each QF. QFs provide updates on agreed milestones to assist in the evaluation of their ability to meet the COD identified in the PPA. Additionally, QFs will inform the Company of any significant issue. Unless there is an indication of a substantial delay in the milestone updates or other significant issues identified by the QF, the Company assumes QF's will meet the COD and generate as identified in the PPA.[47]

[47] *See* CUB CONF Exhibit 110.

This sounds good on paper. However, given the low level of accuracy in 2015 and 2016, this is clearly not a successful strategy. The Company judges their own estimate, which is not based on any forecast methodology as a "commercially reasonable good faith belief"[48] CUB does not believe that this is sufficient, nor accurate.

ii. CUB's recommendation

Forecasted QF power purchases should be based on historical realization. So far, just 80 MW of the 1006 MW that was forecast to come online in 2015 or 2016 is currently used and useful, even though customers are paying for all 1006. Clearly basing a forecast on signed contracts is not reasonable and leads to a violation of the used and useful principle. CUB recommends that any QFs not operating on the date of the final update not be allowed in the TAM. CUB notes that if the QFs are RPS eligible resources, the Company can use the Renewable Adjustment Clause to avoid regulatory lag.

D. Change in Modeling

The Company states that its "general approach to the calculation of NPC using the GRID model" is the same as in previous cases[49] has not changed. The Company also states that, in this filing, the GRID model is the same version as the version in the 2016 TAM[50]. However, CUB feels that this is not representative of the Company's approach. In his testimony, Mr. Dickman describes the adjustment that was at issue in the 2016 TAM, which was meant to address the difference between GRID logic and actual operations, the Day Ahead and Real

[48] UE 307/PAC/100 Dickman/13.
[49] UE 307/PAC/100 Dickman/6.
[50] UE 307/PAC/100 Dickman/7.

Time Balancing Adjustment. GRID perfectly forecasts and economically dispatches all the Company's resources. In reality, the Company must buy power in uniform 25 MW blocks, and then constantly adjust in real time to meet actual customer needs.[51]

As discussed below, CUB takes issue with this approach, but given the approach, CUB also takes issue with the data used in filing. The Company, in the 2016 TAM used 3 years of data for this adjustment[52]. Data that represented the Company's actual experience in the market of buying more often when the market price was high, and selling more often when the market price was low. In this year's filing, the Company retained that initial year of experience, and added another year, making for a total of four years of actual price/volume experience.[53] This is a change to how this adjustment is modeled. But this ignores the Commission's "moratorium" on modeling changes, "to provide time for Staff, parties, and the Commissioners to get a better understanding of the GRID modeling changes that have been made over the past few years."[54] The Commission imposed that moratorium as part of the resolution of this very issue, but the Company ignored it.

Commissioner Bloom, in concurrence requested a Commission workshop, once the parties were reasonably satisfied:[55]

> To give the parties additional time to understand GRID and the various adjustments adopted in this and prior proceedings, we have imposed a one year moratorium on PacifiCorp making further changes to the model. During this moratorium, I ask PacifICorp to

[51] UE 307/PAC/100/Dickman/16.
[52] OPUC Order No. 15-394, page 4.
[53] UE 307/ PAC/100/Dickman/18.
[54] OPUC Order No. 15-394, page 4.
[55] OPUC Order No. 15-394, page 14.

> renew and increase its efforts to explain GRID to the parties with the hope of resolving some of the recurring GRID questions, such as short-term transactions and outage modeling. I would also request a Commissioner workshop once the parties have had time to work together.

The Company has failed to observe the Commission mandated moratorium and the Company has not scheduled a Commissioner workshop. It is not clear to CUB what the basis of this adjustment will be in the future. DA-RT would have increased 2015 power cost estimates by $7 million[56], 2016 NVPC by $8 million[57], and 2017 NVPC by $9 million[58]. The trend is not promising for customers. If the Company is suggesting that it will continue to accumulate data for each year of the TAM, that is certainly a model change. From discussions with the Company, it is CUB's understanding that, because of changes in software and IT, the Company now has more data available to it than before, and is making an attempt to use all relevant data. This may sound reasonable. However, CUB is concerned with potential bias and a lack of a clear model structure. Is the Company allowed to pick the data set that gives it the largest number? Last year, it was an $8 million adjustment. This year, it is a $9.1 million adjustment. Last year, it was based on three years of data. This year, it is based on 4 years of data. And if can change the model this year when it is under a moratorium on changes to the model, what will happen next year when that moratorium runs out.

In part, it should be recognized that in 2014, the Company saw a structural change when entering the EIM, and therefore sales patterns cannot be

[56] UE 307/ PAC/100/Dickman/18.
[57] UE 296/PAC/100//Dickman/30.
[58] UE 307/ PAC/100/Dickman/21.

expected to be the same before as after the change. Part of the argument by the Company, in support of the Day Ahead and Real Time Balancing Adjustment is that the Company's resources happen to be synced with the market[59]. Lack of resource diversity between the Company and the market make for a correlation in sales/purchase volume and price.

However, now that the Company has entered the EIM, the overall structure of the market in which PacifiCorp operates has changed, and, therefore, the diversity as well. The Company discusses this in UE 296 in a discussion of inter-hour dispatch benefits (which customers do not realize either).

> Yes. Before joining the EIM, the Company was dependent on its own resources for all intra-hour balancing. Under the EIM, the CAISO's resources can also be used for intra-hour balancing. In the past, if the Company's loads were less than expected (or if wind generation unexpectedly increased) the Company would work to dispatch down its most expensive available resource. Now, if the highest cost CAISO resource currently dispatched is more expensive than the highest cost Company resource, then the CAISO will back that resource down and the Company will export the output of its most expensive resource to the CAISO[60]

CUB disagrees with the Company's addition of new years of experience without deletion of old years of experience. CUB, believes, as CUB did last year, that the Company should not use the Day Ahead and Real Time Balancing Adjustment. If the Commission continues to allow it, CUB recommends that a clear and fixed modeling structure be decided on and adhered to.

E. Modeling the Day Ahead and Real Time Balancing Adjustment in GRID

CUB opposed the Day Ahead and Real Time Balancing Adjustment in UE 296 on the basis that it was an outboard adjustment to compensate for the

---

[59] UE 296/PAC/100/Dickman/27-28.
[60] UE 296 PAC/100/Dickman/11.

inability of GRID and the Company to reasonably forecast, within the model, accurate power costs. CUB continues to oppose this adjustment and believes that it is a lump sum transfer payment from customers to the Company. In addition, with the data that is used and the data issues mentioned above, CUB is concerned with the use of historical data in power cost forecasts that are meant to be weather normalized. CUB has been researching this issue, and believes that there are several issues at play.

If the Company was forced to buy in reality in 25 MW blocks, but the actual market price was simply the monthly average price, then to buy 25 MW and find out only 23 were necessary, would result in a selloff of 2 MW, but at the same price that they were purchased at. Consequently, there would be no impact. It is a combination of the fact that the Company must buy in discrete units and cannot resale the smaller units for the same price that it paid for the larger units that is important. This occurrence may begin to shrink with the Company's participation in EIM. To that effect, CUB feels that it would be useful to see where the GRID mis-modeling stems from. Some effects may be larger than others, or have interplay.

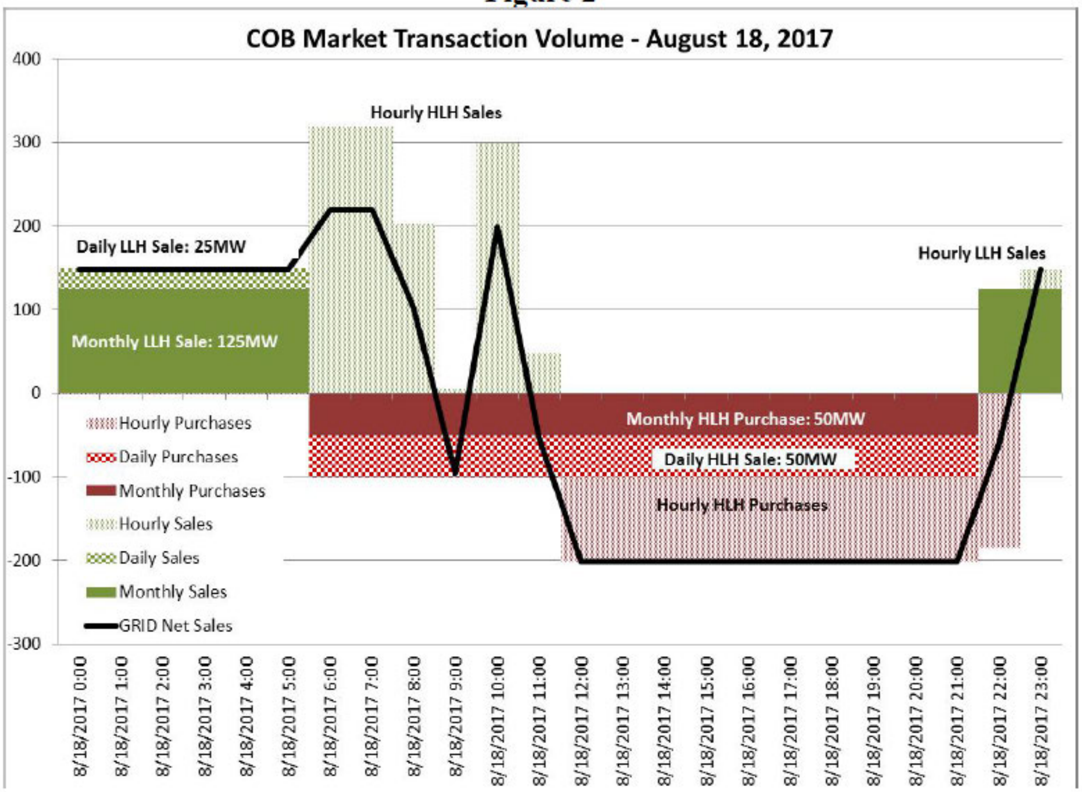
To identify the impact of mis-modeling the 25 MW purchases vs incremental balancing, CUB asked the Company to attempt to model power costs without the Day Ahead and Real Time Balancing, but forcing it to act as the Company must, in real time, selling and purchasing in flat 25 MW blocks, and leveling off as the live hour approaches. At first, the Company did not perform this alternate modeling run, but after discussions, submitted a supplemental data response.[61] In the supplemental response, the Company found that there is an impact from merely forcing GRID to buy and sell in the same units that the Company must trade in.

The other issue, which is that the Company tends to buy when the market price is high and tends to sell when the market price is low, suggests, at least in part, that the Company's resources are approaching capacity at the same point that the rest of the market is tapped out. Similarly, the Company may have many low cost resources available when the rest of the market is also running a surplus. Therefore, the underlying correlation may be a relationship between market prices and capacity factors. CUB also recognizes that a difference between GRID and actual operations is that (to CUB's understanding) GRID balances its system all in one run. Real operations allow sequential, not synchronous sales, purchases and balancing, refining the Company's position.

Figure 2 represents these transactions as a stack.[62]

[61] *See* CUB CONF Exhibit 111.
[62] UE 307/PAC/100/Dickman 21.

Figure 2



However, the description confirms that first monthly purchases are made, then daily, then hourly. The inability to perform in this way could also be another source of inaccuracy in GRID. CUB is still investigating this issue. But CUB does believe that the solution of this is to fix the modeling within Grid to capture the real constraints on the Company, rather than to use historic, non-normalized actual results in a normalized forecast.

F. Many Issues and Updates are Outstanding

At the time of filing, there are updates and corrections outstanding which may have significant impact. CUB looks forward to the Company's reply filing and its address of these issues. CUB also has concerns about the ability to do meaningful discovery in this case. The process has been difficult, and there were multiple data responses that the Company refused to answer. The issue of highly confidential information has delayed access to relevant information in coal costs and coal transportation. More recently the Company has helped CUB get some of the information needed in a useable way, but the delay has been problematic. CUB is hopeful that the process will improve and that the additional rounds of testimony will allow resolution of some issues.

i. The Company plans to update the effects of the Hermiston Contract[63]

ii. The Company plans to update gas prices and contracts[64]

iii. The Company will have more information on QF contracts and be able to provide a better forecast

iv. The Company states that it will update expected EIM benefits due to new entrants in its update filing, and correct an EIM benefit miscalculation of $112,000[65]

G. Conclusion and Recommendations

CUB recommends that the Commission require the Company to pass through to customers all EIM benefits. Currently, this means that the Company would have to re-run the model and some numbers to eliminate the discount for perceived opportunity cost, unused transmission, and intra-regional benefits. Moreover, CUB would like to see an independent analysis or audit of EIM costs and benefits, to guarantee transparency and fairness. CUB also recommends that the customers be held harmless for costs related to fixed coal requirements signed since 2013, specifically because of the known regulatory risk for

[63] UE 307/PAC/100/Dickman/13.
[64] UE 307/PAC/100/Dickman/1.
[65] *See* CUB Exhibit 112.

environmental regulation at the time those contracts were signed. Finally, CUB recommends that the Company continue to work with parties to understand the impacts of DA-RT, and to search for a more appropriate and transparent solution to this issue. This would mean, at a minimum observing the moratorium on modeling changes, and strict compliance with the UE 296 Order.

WITNESS QUALIFICATION STATEMENT

NAME:	Dr. Jaime McGovern
EMPLOYER:	Citizens' Utility Board of Oregon
TITLE:	Senior Utility Analyst
ADDRESS:	610 SW Broadway, Suite 400 Portland, OR 97205
EDUCATION:	Certificate of Attendance, Regulatory Studies Program Institute of Public Studies Michigan State University PhD, Economics W.P. Carey School of Business Arizona State University Masters of Science, Economics Arizona State University Bachelors of Arts, Economics and Mathematics Arizona State University
EXPERIENCE:	Provided testimony or comments in a number of OPUC dockets, including UE 262, UE 283, UM 1633, and UM 1654. Worked as Utility Analyst at the Oregon Public Utility Commission from 2006-2008, providing advice on rate cases, analysis in meetings with the Bonneville Power Administration and performing benchmarking studies regarding telecom and electric competition in the state of Oregon. Economics professor at Mesa Community College and the State University of New York from 2004–2010.

Oregon TAM -UE 307

Highly Confidential Attachment OPUC 67 - "a" through "l" **REDACTED**

Contracts effective for 2017 shown.

a		b	c	d	e	f - g			h	i	j		k - l	
Supplier	Supplier Mine(s)	Plant	Contract Term	Contract Minimum	Contract Maximum	Take or Pay Contract	Liquidated Damages Provision	Other Provisions	Termination Penalty	Termination Penalty Avoidance Clause	Environmental Regulations	Plant Access to a Liquid Coal Market	Process Used for Coal Purchase and Analysis	Risk Reduction Relative to Spot Coal
Bowie Coal Sales, LLC	Sufco, Skyline, Dugout	**Hunter**	2000-2020	[redacted]								No	N/A	N/A
Bowie Coal Sales, LLC	Sufco, Skyline, Dugout, Castle Valley	**Huntington**	2015-2029									No	N/A	N/A
Rhino Energy, LLC	Castle Valley		2012-2017 (Base Term) 2018-2020 (Option Term)									No	N/A	N/A
Black Butte Coal Company	Black Butte	**Jim Bridger**	2015-2017									Limited	Purchase decisions based on RFP process.	See "PacifiCorp's Confidential Long-Term Fuel Supply Plan For The Bridger Plant" provided December 29, 2015
Bridger Coal Company	*Bridger*	*Note - Bridger Coal Company is a Joint Venture of PacifiCorp and Idaho Power Company, joint owners of the Jim Bridger Plant. As such, this agreement is a non-arms length agreement and the terms of the agreement are not applicable.*								[redacted]				
Cloud Peak Energy Resources	Cordero Rojo	**Dave Johnston**	2015 - 2018	[redacted]								Yes	Coal supply purchases for this plant are made with a portfolio approach where Request for Proposals are sent out annually to evaluate the short-term market and longer term market. This approach allows the Company to add favorable purchase options to the portfolio while avoiding the extreme swings sometimes represented in the spot market.	
Westmoreland Kemmerer LLC	Kemmerer	**Naughton**	2017 - 2021									No	N/A	N/A
Wyodak Resources	Wyodak	**Wyodak**	2001 -2022									No	N/A	N/A
Peabody CoalSales	El Segundo/Lee Ranch	**Cholla**	2006-2024									Yes	Purchase decisions based on analysis of available market options.	N/A
Western Energy Company	Rosebud	**Colstrip**	1998-2019									No	No other spot coal is available The Colstrip plant is required to burn Rosebud seam coal under it's plant permit.	N/A
Trapper Mining, Inc.	Trapper	**Craig**	2010-2020									Yes	Purchase decisions based on analysis of available market options.	N/A
Colowyo Coal Company/ Tri-State Generation & Transmission	Colowyo		1992-2017									Yes	Purchase decisions based on analysis of available market options.	N/A
Peabody CoalSales	Foidel Creek/Sage Creek	**Hayden**	2012-2027									Yes	Purchase decisions based on analysis of available market options.	N/A

CUB Exhibit 103 is confidential and was submitted to each party designated to receive confidential information pursuant to Order 16-128.

UE 307 / PacifiCorp
May 12, 2016
CUB Data Request 19

CUB Data Request 19

See UE 307/PAC/100/Dickman/12, lines 18-21. Please explain how the "increased minimum operating level" applies to Oregon customers and Oregon rates, given that the driving Thermal Upgrades/Environmental Controls were never found prudent in Oregon?

Response to CUB Data Request 19

The referenced changes in operating characteristics of the Company's existing thermal resources represent the best information available about the transition adjustment mechanism (TAM) forecast period and are thus appropriately included in the net power costs (NPC) forecast.

CUB Exhibit 105 is confidential and was submitted to each party designated to receive confidential information pursuant to Order 16-128.

CUB Data Request 53

Please provide model results with coal from minimum take contracts being valued at market according to the forward curves.

Response to CUB Data Request 53

The Company objects to this request as overly broad and burdensome and not likely to lead to admissible evidence in this proceeding. Opportunities for coal sales are limited and highly dependent on delivery location and the costs associated with available transportation options. The Company does not prepare forward market price curves for coal and has not performed the analysis requested above. Please also refer to the Company's response to CUB Data Request 52.

UE 307 / PacifiCorp
June 23, 2016
OPUC Data Request 45

OPUC Data Request 45

The Company states that "PSE and APS are expected to participate in EIM starting in October 2016, so twelve months of benefits from their participation are also included in the 2017 TAM. "(See PAC/100, Dickman/30). Please provide a narrative describing the steps taken to determine this benefit. Please demonstrate how this benefit was calculated showing all formulae. Please provide all source data from which this benefit was calculated. Please provide a list of all assumptions made for this calculation.

Response to OPUC Data Request 45

The Energy and Environmental Economics Inc. (E3) studies for Puget Sound Energy (PSE) and the Arizona Public Service Company (APS) estimated a total annual benefit to all existing participants (California Independent System Operator (CAISO), PacifiCorp, and NV Energy) of $2 million per year. In its UE-296 Reply Testimony, the Company proposed that the E3 study results be allocated among the existing participants based on same ratios employed by the Industrial Customers of Northwest Utilities (ICNU) with regard to the flexibility reserve diversity benefits from these participants. The Company's share works out to approximately 17 percent of the total.

The Company's current filing continues to use the same methodology. Please refer to the confidential work papers provided concurrently with the Direct Testimony of Company witness, Brian S. Dickman, specifically row 38 to 40 of the tab entitled "EIM" in the file entitled "_ORTAM17 NPC Study_2016 03 18 CONF.xlsm."

The E3 study benefits to existing participants were $1.4 million for APS and $600,000 for PSE, as shown in cells U39:U40. The PacifiCorp share of roughly 17 percent is calculated from the E3 studies reported reserve benefit to existing participants, shown in cells "R39:R40," and the share of the total ICNU proposed for PacifiCorp, shown in cells "S39:S40". The monthly PacifiCorp share is shown in cells "V39:V40," and is applied in all months after the projected EIM start date for the new participant, shown in cells "W39:W40."

The E3 energy imbalance market (EIM) benefits assessments containing the aforementioned source data for APS and PSE are publicly available and can be accessed by utilizing the following website links:

APS: http://www.caiso.com/Documents/ArizonaPublicService-ISO-EnergyImbalanceMarketEconomicAssessment.pdf

PSE: http://www.caiso.com/Documents/PugetSound-ISO_EnergyImbalanceMarket-BenefitsAnalysis.pdf

The flexibility reserve diversity values employed by ICNU are located in the footnote on page 31 of the Opening Testimony of Mr. Bradley Mullins in Docket UE 296.

CUB Exhibit 108 is confidential and was submitted to each party designated to receive confidential information pursuant to Order 16-128.

CUB Exhibit 109 is confidential and was submitted to each party designated to receive confidential information pursuant to Order 16-128.

CUB Data Request 22

See UE 307/PAC/100/Dickman/13. Solar QF Purchases.

(a) If the Company was to build the solar capacity that is in the (1) largest and (2) smallest QF contract, what would be the production time?

(b) Please provide, for the last 10 years, the: (1) forecasted QF MWs in each TAM (at time of filing); (2) actual QF MW's for each period covered by the TAM; (3) forecasted number of QF contracts in each TAM (at time of filing); and (4) actual number of QF contracts for each period covered by the TAM.

(c) (1) How many QF contracts does the Company include in the 2017 TAM? (2) With how many distinct entities has the Company signed QF contracts for the 2017 TAM? We are attempting to learn if some entities are submitting multiple contracts.

(d) *See id.* at lines 20-21. What does the Company mean by "expected"? Is there a forecast methodology to determine what percentage of those contracts will materialize? With what level of certainty does the Company "expect" these MWs to come online?

Response to CUB Data Request 22

(a) The Company objects to this request as overly broad and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections, the Company responds as follows:
The Company assumes that the use of the term "production time" in this request is intended to simply mean the time to construct the solar project. It should be noted, however, that the use of the term "production time" is highly variable. However, based upon the Company's foregoing assumption that "production time" is intended to mean "the time to construct the solar project," and assuming all site rights, interconnection agreements, construction permits and equipment have been obtained for the respective projects, the Company's approximate assumed construction schedules for the smallest solar qualifying facility (QF) projects and largest solar QF projects would be as set forth below. It is important to note that construction times can vary based on the type of solar photovoltaic (PV) array (i.e., fixed tilt versus single-axis trackers) and site location. Accordingly, the assumptions set forth below are approximate:

(1) the assumed time to construct a 2 megawatt (MW) solar project is estimated to be approximately two to four months (depending on location and technology), and

(2) the assumed time to construct an 80 MW solar project is estimated to be approximately eight to 12 months (depending on location and technology).

(b) (1) For the solar QFs included in transition adjustment mechanisms (TAM) over the past 10 years, please refer to Attachment CUB 22 -1.

(2) Please refer to Attachment CUB 22 -2, which provides actual solar QF project MWs over the referenced period.

(3) Please refer to the Company's response to subpart (b)(1) above.

(4) Please refer to the Company's response to subpart (b)(2) above.

(c) (1) Please refer to the Company's response to subpart (b)(1) above.

(2) Please refer to Attachment CUB 22 -3.

(d) The Company determines the solar QF projects that are expected to achieve commercial operation during the forecast period based on the commercial operation date (COD) identified in the executed power purchase agreement (PPA), informed by continual discussions with each QF. QFs provide updates on agreed milestones to assist in the evaluation of their ability to meet the COD identified in the PPA. Additionally, QFs will inform the Company of any significant issue. Unless there is an indication of a substantial delay in the milestone updates or other significant issues identified by the QF, the Company assumes QF's will meet the COD and generate as identified in the PPA.

CUB Data Request 30

Please see UE 307 PAC/100/Dickman/16. CUB believes that the discrepancy resulting from the discrete purchases of 25MW blocks, vs non-discrete actual load could be modeled within GRID with something akin to:

$$\min B \ st.25 \times B \geq forecasted\ load$$

then $$E = 25 \times B$$

Where **E** is in MWs

Then, the real time balancing would insist that selloff equal (E - actual load**).** CUB understands that the optimization logic would have to take into account whether this additional transaction cost would outweigh the benefits of in house dispatch. Please contact Jaime McGovern directly via email or cell phone if there are discussion points on this question.

Or, in general, force grid to model purchases in 25MW blocks. Please answer and explain whether GRID can internalize these 25MW blocks into the model in a forecasting manner.

Response to CUB Data Request 30

The Company has not done a detailed analysis of the code and the potential modeling options for enforcing 25 megawatt (MW) block transactions and other transaction granularity constraints. However, it is unlikely that the Generation and Regulation Initiative Decision Tool (GRID) could internalize these limits without significant code alterations, if it was possible at all.

While automating the process would be difficult, the existing model could perform similarly using multiple scenarios with external calculations:

1. Run GRID normally.

2. Extract hourly balancing results and round up purchases to nearest 25 MW, round down sales to nearest 25 MW.

3. Import these transactions as fixed schedules (Hourly Short-Term Firm (STF)) and set the market capacity in GRID for both purchases and sales to zero.

4. Rerun GRID to optimize the thermal fleet around the block transactions.

Note: "block transactions" refers to both the 25 MW standard volume, as well as the monthly and daily products for heavy load hour (HLH) and light load hour (LLH) periods. The day-ahead HLH product spans 16 hours from 6:00 am to 10:00 pm. If the Company has a long position or short position in a few of those hours, this product is not a good fit, as many of the hours are unneeded. More granular products are uncommon and tend to be more expensive. The limited availability and cost of such products is not reflected in the Company's scaled hourly market prices, nor is the limited availability and cost elasticity of hourly products. In addition, GRID balancing logic runs for each hour independently, so it would not be able to optimize a 25 MW block across a 16-hour span.

CUB Data Request 46

In light of the increase in first quarter benefits since NV Energy joined the EIM ($10.8 million in Q2 2015 vs. $3.82 million in Q1 2015, an increase of 183%), please explain how the Company plans to revise its expectation of benefits to PAC as other entities join. How does this approach apply to the forecast in benefits for the 2017 TAM period?

Response to CUB Data Request 46

The Company is continuing to gather benefit results from inter-regional transactions with both the California Independent System Operator (CAISO) and NV Energy and will incorporate them in its Update Filing.

The increase in benefits resulting from NV Energy's participation appears to be related to the new path NV Energy provides for transfers between PacifiCorp East (PACE) and the CAISO. The Company is evaluating the actual transfers between PACE and NV Energy and intends to update its calculation of inter-regional benefits, including refining the calculation of projected benefits based on these actual transfers, in the Company's Update Filing.

The participation of Puget Sound Energy (PSE), and Portland General Electric (PGE) is not expected to result in new transfer capability with CAISO, so revisions to the benefits associated with these new participants are not anticipated at this time. Transfer capability with Arizona Public Service Company (APS) may result in additional transfer capability with the CAISO, but it is still undetermined what that capacity may be or whether additional benefits may be realized.

In responding to this data request the Company discovered that benefits associated with PGE's participation in EIM were inadvertently not included in the total net power costs (NPC) reflected in the Company's Direct Filing. As a result, total Company NPC is overstated by $112,000. This correction will be incorporated in the Company's Update Filing. For supporting details, please refer to rows 41 and 45 of tab "EIM" in the confidential work paper entitled "_ORTAM17 NPC Study_2016 03 18 CONF.xlsm" provided concurrently with the Direct Testimony of Company witness, Brian S. Dickman.