

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



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1 My name is Jaime McGovern, and my qualifications are listed in CUB Exhibit  
2 101.

3 **I. Introduction**

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

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<sup>1</sup> UE 307 PAC/100/Dickman/3.

<sup>2</sup> UE 307 PAC/100/Dickman/9.

**Table 1**  
**Net Power Cost Reconciliation**

	(\$ millions)	\$/MWh
<b>OR TAM 2016</b>	<b>\$1,521</b>	<b>\$24.94</b>
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)	
<b>Total Increase/(Decrease) to NPC</b>	<b>\$45</b>	
<b>OR TAM 2017</b>	<b>\$1,566</b>	<b>\$25.86</b>

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

5 **II. CUB's Issues**

6 **A. Coal Costs and Coal Plant Costs**

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

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<sup>3</sup> UE 307 PAC/100/Dickman/9.

1 environmentally risky resources years into the future. Since 2013, the Company  
2 has signed new coal contracts for Huntington, Jim Bridger, Dave Johnston and  
3 Naughton<sup>4</sup>.

4 *i. JIM BRIDGER*

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

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

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

15 Mr. Dickman provides additional testimony describing the  
16 circumstances affecting coal generation in the TAM filings,  
17 including reductions in generation at the Jim Bridger plant.<sup>8</sup>

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

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<sup>4</sup> See CUB EXHIBIT 102.

<sup>5</sup> UE 307/PAC 100/Dickman 9.

<sup>6</sup> UE 307/PAC 200/Ralston 12.

<sup>7</sup> UE 307/PAC 200/Ralston/3.

<sup>8</sup> UE 307/PAC 200/Ralston/14.

<sup>9</sup> UE 307/PAC 100/Dickman/10.

<sup>10</sup> UE 307/PAC 100/Dickman/28.

1 The primary factor contributing to lower coal production and coal  
2 deliveries in the 2017 TAM is reduced generation at the Jim Bridger  
3 plant.<sup>11</sup>

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

5  
6 Additional details regarding the cost of coal during the test year  
7 are provided in the direct testimony of Mr. Ralston.<sup>12</sup>

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

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

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

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

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<sup>11</sup> UE 307/PAC 200/Ralston/13.

<sup>12</sup> UE 307/PAC 100/Dickman/11.

<sup>13</sup> See CONF CUB EXHIBIT 103 row 990.

<sup>14</sup> UE 307/PAC 100/Dickman/12.

<sup>15</sup> See CONF CUB EXHIBIT 103 row 990.

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

4 The Company responded non-informatively:

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

10 CUB therefore finds no basis to include the subsequent increased average costs,  
11 increased minimum operating level, and other related costs in Oregon rates.

12 These retrofits have not been examined and found to be prudent. These SCR  
13 investments at Bridger were reviewed in LC 57 and the Commission declined  
14 acknowledgement for four reasons:

15 Based upon the information we have at this time, we decline to  
16 acknowledge Action Item 8c related to Bridger Units 3 and 4 for  
17 four reasons. First, some of the modeled alternatives suggest that  
18 the installations of SCRs are not the lowest cost resource option. For  
19 example, as described on page 4 of Staffs Final Comments dated  
20 January 10, 2014, alternative D runs demonstrate that it is more  
21 economical to retire Bridger 3 and 4 than to install the SCR  
22 equipment. Based upon the information we currently have, we  
23 cannot dismiss these results as unrealistic or unreasonable.

24 Second, we concur with Staff that there are gaps in PacifiCorp's  
25 analyses. As Staff notes, PacifiCorp did not consider the potential  
26 tradeoffs between units at Bridger 3 and 4 or between coal plants  
27 to identify the most cost effective compliance options from a state  
28 or fleet perspective. Additional analyses on these issues would  
29 have resulted in more information for us to make an informed  
30 decision on acknowledgment.

31 Third, Staff and other participants have raised several other specific  
32 issues related to the merit or lack of merit of installing SCRs at  
33 Bridger 3 and 4, such as the impact of retirement on reliability, inter-  
34 temporal and fleet trade-off analysis between units, or the impact

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<sup>16</sup> See CUB Exhibit 104.

1 of retirement on future transmission investments. However, we lack  
2 the necessary information in this proceeding to weigh these issues  
3 and they will be more thoroughly investigated in a future rate case  
4 proceeding.

5 Finally, PacifiCorp is going ahead with the investments in installing  
6 SCRs regardless of our decision in this proceeding. We will  
7 undertake a thorough and fair review of the prudence of  
8 PacifiCorp's decision in a future rate case proceeding.<sup>17</sup>

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

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

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

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<sup>17</sup> *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.

<sup>18</sup> LC 57 Opening Comments of the Citizens' Utility Board of Oregon, pages 12-20.

1 **a. CUB Recommendation:**

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

7  <sup>19, 20</sup>

8 **ii. NEW COAL CONTRACTS**

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

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

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<sup>19</sup> See CONF CUB Exhibit 105.

<sup>20</sup> The Company, in the modeling, did not reflect all impacts of the SCR. These additional impacts could have the effect of increasing the adjustment.

<sup>21</sup> See CUB exhibit 102.



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

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

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

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<sup>22</sup> <http://www.nrel.gov/docs/fy14osti/60575.pdf>

<sup>23</sup> See CUB exhibit 106.

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

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

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

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

14 ***CUB Recommendation:***

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

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<sup>24</sup> UE 307 PAC/100/Dickman/9.

1 **B. EIM Costs/Benefits**

2 **i. INTRA-REGIONAL BENEFITS**

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

- 11 1. Inter-regional dispatch;
- 12 2. Intra-regional dispatch; and
- 13 3. Flexibility reserves.<sup>27</sup>

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

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

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<sup>25</sup> UE 307/PAC 100/Dickman/26.

<sup>26</sup> See CUB exhibit 107.

<sup>27</sup> See CUB exhibit 107.

<sup>28</sup> See CUB exhibit 107.

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

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

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

15 Moreover, the Company explains how this benefit is realized:

16 Q: What is the primary change in the Company's day-to-day  
17 operations as a result of EIM?

18 A. Before EIM operation, the Company manually dispatched most  
19 of its regulating resources to balance the system within the hour,  
20 generally via phone calls to plant personnel. As a result, requests  
21 would typically be sent to the fastest responding and most flexible  
22 units first, to ensure system balance and reliability was maintained.  
23 As the balance returned to normal, additional requests would be  
24 sent to dispatch up lower-cost units and dispatch down higher-cost  
25 units. This approach could result in dispatch of higher cost units  
26 than strictly necessary in a computer-optimized world. Under EIM,  
27 dispatch instructions are automatically sent to all participating  
28 resources every five minutes. This helps minimize costs by ensuring  
29 the lowest cost resources that are available are dispatched.<sup>30</sup>

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

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<sup>29</sup> UE 296/PAC/100 /Dickman/10.

<sup>30</sup> UE 296/PAC/100/Dickman/10-11.

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

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

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

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<sup>31</sup> UE 296/PAC/100/Dickman/12.

<sup>32</sup> See CUB Exhibit 107.

<sup>33</sup> 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.

1 balancing increased rates by \$8 million.<sup>34</sup> This year the Company modeled 4  
2 years of data (July, 2011 to June, 2015) and is proposing a \$9.1 million addition to  
3 rates in order to remove this forecast bias<sup>35</sup>.

4 ***CUB Recommendation:***

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

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

17 ***ii. ACTUALS DISCOUNTED FOR FORECASTING***

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

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<sup>34</sup> OPUC Order No. 15-394 at 2.

<sup>35</sup> UE 307/PAC/100/Dickman/18

1 participation. Cost? Check. So, in the calculation of net benefits from EIM  
2 participation, there are multiple components that go into the benefits column  
3 and multiple elements that go into the costs column. There is a distinction to be  
4 aware of: actual benefits that flow to the Company for a particular year, say  
5 2016, compared to forecasted benefits which flow to customers. Customers do  
6 not get actual benefits that flow above the forecasted level, unless they are so  
7 significant that they trigger the PCAM deadband, and even then, they are  
8 subject to sharing. Therefore, getting the forecast right is important.  
9 Systematically diluting or reducing forecasted benefits is not benign in nature. All  
10 bias is not eliminated by a dollar for dollar true-up.

11 In a confidential response to OPUC Staff,<sup>36</sup> the Company provided a  
12 summary of actual benefits from EIM. CUB, after reviewing the responses  
13 regarding EIM calculations believes that the Company computes benefits in the  
14 following way:

15 The import benefits are calculated as:

$$\textit{Import Benefit} = \textit{import avoided cost} - \textit{import cost}$$

16 The export benefit is calculated similarly:

$$\textit{Export Benefit} = \textit{Export revenue} - \textit{export cost}$$

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

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<sup>36</sup> See CUB CONF Exhibit 108.

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

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

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<sup>37</sup> See CUB CONF Exhibit 108.



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

6 ***CUB Recommendation:***

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

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

10 PacifiCorp also discounts forecasted sales by discounting the actual basis  
11 of the forecast--the actual exports. The general picture is the following. The  
12 Company has generation resources that are, at times, economical for dispatch  
13 beyond the needs of their own customers. When this is true, the Company has  
14 several options. First, and somewhat traditionally, the Company can contract  
15 sales-for-resale. They do this at the Mid-Columbia Market (Mid-C) and COB. The  
16 generation that the Company exports to the California Market, either through  
17 COB or EIM follows the same physical path, and requires the same transmission  
18 capacity. Therefore, they can be thought of as substitutes in revenue  
19 generation. The Company either commits power to COB in a signed contract, or  
20 it submits power to EIM which CAISO, at its economical discretion can dispatch  
21 from PAC. When the Company makes the decision to commit generation (and  
22 the corresponding transmission) to COB, it does so on the basis that the revenue  
23 of the sale at COB is higher than the expected value from withholding that  
24 power from COB and reserving it for the EIM. This decision may or may not turn

1 out to be wise in retrospect. The Company may reserve power, failing to secure  
2 a COB contract, only to find that the revenue it receives from the CAISO EIM  
3 market is lower, or the power is not sold at all.

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

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

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

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<sup>38</sup> See CUB CONF Exhibit 109.

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

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

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

1           **CUB Recommendation:**

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

7           **iv. GOT BENEFITS?**

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

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<sup>39</sup> TABLE 2 UE 296/PAC/100/Dickman/9.

**Table 2**  
**Total-Company EIM-Related Benefits and Costs**

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

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

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<sup>40</sup> See CUB CONF Exhibit 107.

1           ***CUB Recommendation:***

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

6           **C. Increased Purchased Power Costs -**

7           ***i. CUB's Understanding***

8           Qualifying Facilities ("QF") power is **the main** driver of higher purchased  
9 power costs. This is not pocket change. The Company admits there are an  
10 additional \$99 million in QF purchases over the 2016 TAM forecast. Lower market  
11 prices are forecasted in 2017.<sup>41</sup> Market purchases in the 2016 TAM were included  
12 at an average price of "\$27.23/MWh, while market purchases in the current case  
13 are included at an average price of \$24.60/MWh, a 10 percent decrease.<sup>42</sup>  
14 However, customers will not realize the benefit of these low priced markets  
15 because of the QF contracts that the Company has forecasted into the 2017  
16 TAM. CUB understands that the Company must accept QF contracts that are  
17 presented to it. However, CUB disagrees that this number, either number of  
18 contracts, or number of MWs contracted should be the forecasted number for  
19 the NVPC. In the 2015 TAM, only 80 of the 96 MW forecasted actually came  
20 online.<sup>43</sup> The next year, the forecasting error became drastically worse. In the  
21 2016 TAM, PAC forecasted 1006.43 MW of solar, but only 80 MW is actually online

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<sup>41</sup> UE 307/PAC/100/ Dickman/10.

<sup>42</sup> UE 307/PAC/100/Dickman/10.

<sup>43</sup> See CUB CONF Exhibit 110.

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

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

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

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<sup>44</sup> See CUB CONF Exhibit 110.

<sup>45</sup> See CUB CONF Exhibit 110.

<sup>46</sup> UE 307 PAC/100/Dickman/107.

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

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

17           The Company determines the solar QF projects that are expected to  
18 achieve commercial operation during the forecast period based on  
19 the commercial operation date (COD) identified in the executed  
20 power purchase agreement (PPA), informed by continual discussions  
21 with each QF. QFs provide updates on agreed milestones to assist in  
22 the evaluation of their ability to meet the COD identified in the PPA.  
23 Additionally, QFs will inform the Company of any significant issue.  
24 Unless there is an indication of a substantial delay in the milestone  
25 updates or other significant issues identified by the QF, the Company  
26 assumes QF's will meet the COD and generate as identified in the  
27 PPA.<sup>47</sup>  
28

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<sup>47</sup> See CUB CONF Exhibit 110.



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

6 **ii. CUB's recommendation**

7 Forecasted QF power purchases should be based on historical realization.  
8 So far, just 80 MW of the 1006 MW that was forecast to come online in 2015 or  
9 2016 is currently used and useful, even though customers are paying for all 1006.  
10 Clearly basing a forecast on signed contracts is not reasonable and leads to a  
11 violation of the used and useful principle. CUB recommends that any QFs not  
12 operating on the date of the final update not be allowed in the TAM. CUB notes  
13 that if the QFs are RPS eligible resources, the Company can use the Renewable  
14 Adjustment Clause to avoid regulatory lag.

15 **D. Change in Modeling**

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

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<sup>48</sup> UE 307/PAC/100 Dickman/13.

<sup>49</sup> UE 307/PAC/100 Dickman/6.

<sup>50</sup> UE 307/PAC/100 Dickman/7.

1 Time Balancing Adjustment. GRID perfectly forecasts and economically  
2 dispatches all the Company's resources. In reality, the Company must buy  
3 power in uniform 25 MW blocks, and then constantly adjust in real time to meet  
4 actual customer needs.<sup>51</sup>

5 As discussed below, CUB takes issue with this approach, but given the  
6 approach, CUB also takes issue with the data used in filing. The Company, in the  
7 2016 TAM used 3 years of data for this adjustment<sup>52</sup>. Data that represented the  
8 Company's actual experience in the market of buying more often when the  
9 market price was high, and selling more often when the market price was low. In  
10 this year's filing, the Company retained that initial year of experience, and  
11 added another year, making for a total of four years of actual price/volume  
12 experience.<sup>53</sup> This is a change to how this adjustment is modeled. But this  
13 ignores the Commission's "moratorium" on modeling changes, "to provide time  
14 for Staff, parties, and the Commissioners to get a better understanding of the  
15 GRID modeling changes that have been made over the past few years."<sup>54</sup> The  
16 Commission imposed that moratorium as part of the resolution of this very issue,  
17 but the Company ignored it.

18 Commissioner Bloom, in concurrence requested a Commission workshop,  
19 once the parties were reasonably satisfied:<sup>55</sup>

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

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<sup>51</sup> UE 307/PAC/100/Dickman/16.

<sup>52</sup> OPUC Order No. 15-394, page 4.

<sup>53</sup> UE 307/ PAC/100/Dickman/18.

<sup>54</sup> OPUC Order No. 15-394, page 4.

<sup>55</sup> OPUC Order No. 15-394, page 14.

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

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

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

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<sup>56</sup> UE 307/ PAC/100/Dickman/18.

<sup>57</sup> UE 296/PAC/100//Dickman/30.

<sup>58</sup> UE 307/ PAC/100/Dickman/21.

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

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

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

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

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

26 CUB opposed the Day Ahead and Real Time Balancing Adjustment in UE  
27 296 on the basis that it was an outboard adjustment to compensate for the

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<sup>59</sup> UE 296/PAC/100/Dickman/27-28.

<sup>60</sup> UE 296 PAC/100/Dickman/11.

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

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

18         To identify the impact of mis-modeling the 25 MW purchases vs  
19 incremental balancing, CUB asked the Company to attempt to model power  
20 costs without the Day Ahead and Real Time Balancing, but forcing it to act as  
21 the Company must, in real time, selling and purchasing in flat 25 MW blocks, and  
22 leveling off as the live hour approaches. At first, the Company did not perform  
23 this alternate modeling run, but after discussions, submitted a supplemental data

1 response.<sup>61</sup> In the supplemental response, the Company found that there is an  
2 impact from merely forcing GRID to buy and sell in the same units that the  
3 Company must trade in.

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

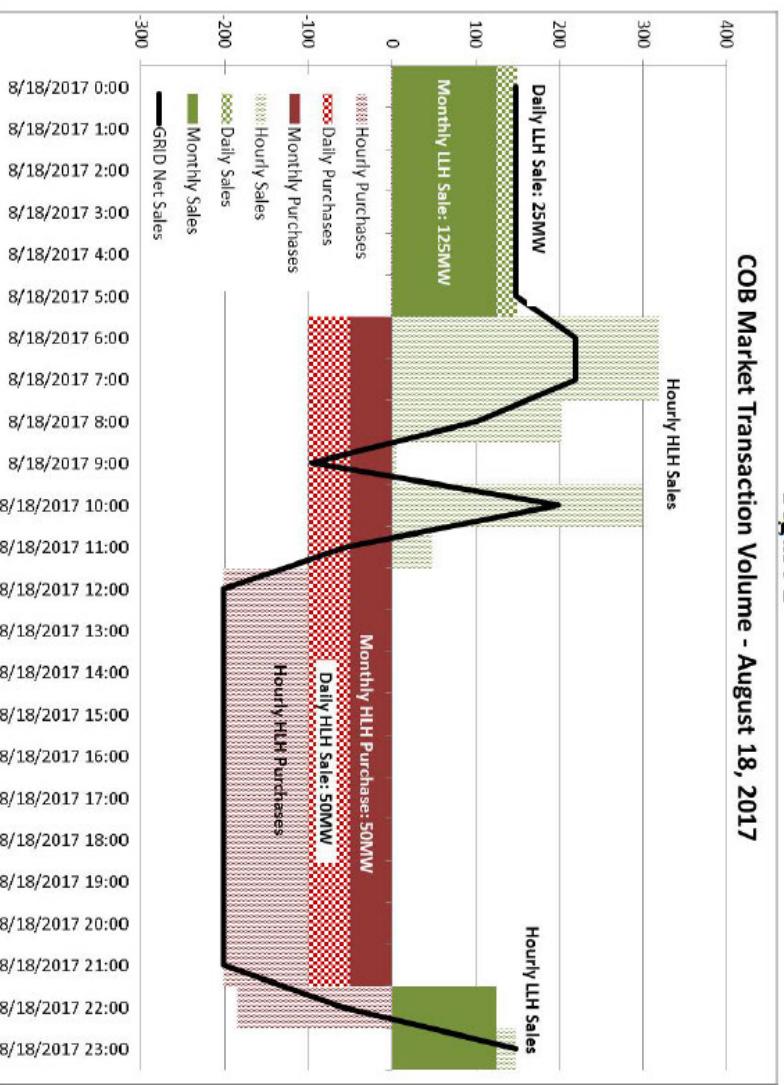
14         Figure 2 represents these transactions as a stack.<sup>62</sup>

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<sup>61</sup> See CUB CONF Exhibit 111.

<sup>62</sup> UE 307/PAC/100/Dickman 21.

Figure 2



- 1 However, the description confirms that first monthly purchases are made,
- 2 then daily, then hourly. The inability to perform in this way could also be another
- 3 source of inaccuracy in GRID. CUB is still investigating this issue. But CUB does
- 4 believe that the solution of this is to fix the modeling within Grid to capture the
- 5 real constraints on the Company, rather than to use historic, non-normalized
- 6 actual results in a normalized forecast.
- 7 **F. Many Issues and Updates are Outstanding**
- 8 At the time of filing, there are updates and corrections outstanding which
- 9 may have significant impact. CUB looks forward to the Company's reply filing
- 10 and its address of these issues. CUB also has concerns about the ability to do
- 11 meaningful discovery in this case. The process has been difficult, and there were

1 multiple data responses that the Company refused to answer. The issue of highly  
2 confidential information has delayed access to relevant information in coal costs  
3 and coal transportation. More recently the Company has helped CUB get some  
4 of the information needed in a useable way, but the delay has been  
5 problematic. CUB is hopeful that the process will improve and that the  
6 additional rounds of testimony will allow resolution of some issues.

- 7 *i. The Company plans to update the effects of the Hermiston Contract<sup>63</sup>*  
8 *ii. The Company plans to update gas prices and contracts<sup>64</sup>*  
9 *iii. The Company will have more information on QF contracts and be able to*  
10 *provide a better forecast*  
11 *iv. The Company states that it will update expected EIM benefits due to new*  
12 *entrants in its update filing, and correct an EIM benefit miscalculation of*  
13 *\$112,000<sup>65</sup>*

#### 14 **G. Conclusion and Recommendations**

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

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<sup>63</sup> UE 307/PAC/100/Dickman/13.

<sup>64</sup> UE 307/PAC/100/Dickman/1.

<sup>65</sup> See CUB Exhibit 112.



1 environmental regulation at the time those contracts were signed. Finally, CUB  
2 recommends that the Company continue to work with parties to understand the  
3 impacts of DA-RT, and to search for a more appropriate and transparent solution  
4 to this issue. This would mean, at a minimum observing the moratorium on  
5 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

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**EDUCATION:** Certificate of Attendance, Regulatory Studies Program  
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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.

Highly Confidential Attachment OPUC 67 - "a" through "I"

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									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.												
Cloud Peak Energy Resources	Cordero Rojo	Dave Johnston	2015 - 2018									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 its 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](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:

$$\min B \text{ st. } 25 \times B \geq \text{forecasted load}$$

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.