BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 307

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

REBUTTAL/CROSS ANSWERING TESTIMONY OF THE CITIZENS' UTILITY BOARD OF OREGON

August 12, 2016

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

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

I. Introduction

Pursuant to Administrative Law Judge ("ALJ") Rowe's prehearing conference memorandum of April 26, 2016, the Citizens' Utility Board of Oregon ("CUB") submits its Rebuttal/Cross-Answering Testimony in UE 307. This Rebuttal/Cross Answering Testimony addresses issues raised in Opening Testimony by parties and by PacifiCorp's ("PAC" or "the Company") Reply Testimony, all in response to the Company's 2017 TAM filing, requesting approximately $380 million dollars in net power costs ("NPC"). This would bring NPC back up to a level higher than when the Company joined the EIM in 2014[1], even though several important factors have changed since then. Gas prices are now about half the price they were in 2014, the economy is recovering, and the Energy

[1] PAC/400/Dickman/6/Figure 1.

Imbalance Market ("EIM") is meant to provide savings for customers in the form of efficiencies.

CUB addresses the issues raised in prior testimony and argues that the Company has not demonstrated either the reasonableness or the methodology of its power cost estimates, even after repeated questioning and request for clarity. The Company makes many claims that are in direct conflict with CAISO representatives and other parties to this docket.

In general, CUB believes that the Company's approach is flawed. The GRID tool, which began as a hydro modeling tool, has been tweaked to fit current circumstances. Despite being extremely complex, it has many limitations that make the Company's power cost forecasting methodology non-transparent. Couple that with the fact that the Company has not been forthcoming in its duty to work with parties to understand the calculations, and the process is not unbiased.

II. Issues

Below, CUB addresses the following outstanding concerns:

1. The Company's lack of transparency;
2. EIM benefit calculations;
3. DART adjustments;
4. PURPA facilities and recovery; and
5. Take or Pay Coal.

III. The Company's Lack of Transparency

As always, power cost filings are adjudicated on a much shorter schedule than general rate cases, but are no less important. For this case, the filed NPCs (totaling $380 million) are equivalent to that of a significant capital investment such as a gas plant, major solar plant, or wind farm. However, these NPCs lack the thirty year amortization window of the aforementioned capital investments, and, instead, are collected from customers in one year. Extremely large costs, short collection timeframe, and a short power cost docket make for high stakes out of the gate. This should highlight the need for parties to be as communicative and straightforward as possible. Below, CUB discusses some of the instances where the Company's misrepresentations, shifting answers, and lack of communication have made it impossible to discern whether the power costs in this case were forecast properly.

A. Stack of resources submitted to CAISO

There is some disagreement about how EIM net benefits are calculated, which resources are being costed, dispatched and at what cost.

EIM export benefits should simply be:

$$EIM\ Export\ benefits = Export\ Revenue - Export\ Cost$$

Staff contends, and CUB concurs, that the Company’s calculation of EIM export net benefits commits several errors. The Company is using something other than the pure marginal cost for the cost side of the equation. Therefore, CUB has been trying to get a better picture of how the Company submits resources to CAISO and how CAISO dispatches those resources. CUB has concerns regarding PacifiCorp customers paying the market price for electricity, instead of the resource cost, given they have contributed to building a system with efficiencies, reserves, and low-cost dispatchable resources. CUB was unclear, and wanted to confirm that the Company reserved its least cost resources for its customers. To get a more clear understanding of what happened to those resources submitted to CAISO, in its DR 72 CUB asked:

> CUB also asked about priority of resources served. The following is CUB's understanding:
>
> The Company stated that the PAC customers get served with lowest cost resources as a priority. Then the Company submits resources to CAISO. CAISO then pulls the highest cost resources from the stack. CUB asked about what happened if the Company used low cost resources for PAC customers and CAISO picked off the top of the stack, leaving mid-cost resources unutilized. The Company stated that all resources from the resource just below CAISO market price down to the least expensive one would get utilized, and that the Company submitted all resources not used by customers to CAISO.
>
> From Staff's testimony, CUB reads that the Company costs exports according to the bid price of the highest priced resource in the stack at the time.
>
> **Please reconcile the above seeming contradiction:**
>
> **Does the Company always submit all resources above those needed to serve PAC customers?**
>
> **(a) If so, what determines if those surplus resources are submitted to CAISO, or reserved for COB contracts. Please be explicit, and provide formulas used in making decisions.**[2]

The Company responds with an entirely different explanation of how resources are submitted to the EIM, without actually answering CUB's question:

> The energy imbalance market (EIM) is an intra-hour market that utilizes a base schedule submitted by PacifiCorp for how it will meet its load requirements and ancillary service obligations for each operating hour. Included in the base schedule that is submitted to the California Independent System Operator (CAISO) at 40 minutes prior to each operating hour, is the net interchange amount (imports and exports). The imports or exports that are scheduled prior to the hour include bilateral transactions, such as Mid-Columbia (Mid-C) purchases or sales. Bilateral purchases or sales are contracted for prior to the operation of EIM.
>
> The CAISO security constrained economic dispatch model (SCED) is used to optimize PacifiCorp's participating generation resources relative to the forecast of the combined balancing authority area (BAA) – *CAISO +*

[2] CUB Exhibit 201.

> *Nevada + PacifiCorp East (PACE) +PacifiCorp West (PACW)* **–** load and variable energy resources for each operating hour.
>
> **PacifiCorp submits a bid for each of its participating resources that are scheduled on-line for each operating day**. The CAISO real-time market optimization serves load by the most economic resource, drawn from the larger pool of resources, to most efficiently match load with supply while ensuring reliability.
>
> The SCED model used by the CAISO does not "pull" from the highest cost resource from the stack, it utilizes the marginal resource as the next available unit cost of generation or next available unit cost of decrement. Simplistically, the marginal resource is determined by the SCED as the least cost available capacity on the system. There could be additional units on-line that have higher operating costs, or higher in the stack resources, but if there are lower cost resources that have available capacity these units will set the locational marginal price and be used to determine the cost of the next megawatt (MW) produced.
>
> **PacifiCorp's statement that its lowest cost resources are used to serve its own load first, was a simplification of the CAISO SCED model optimized solution**. Essentially, each EIM entity benefits by having its load served by the most economic resources, whether they be owned by PacifiCorp, Nevada Energy or a generator within the CAISO Balancing Authority Area subject to transmission and reliability constraints.[3]

This answer does not address the questions that parties have regarding how the Company decides whether to contract at COB in the day ahead market, or reserve for the EIM. It does not explain how the Company costs the resources submitted to the stack, the contradiction that CUB identified in its question. This is a fundamental problem because if CA or NV customers are being served with PAC's low cost resources when PAC customers could be benefiting from those economies, NPC are higher. It is clear that this is still a point of contention because PacifiCorp has not demonstrated that it subtracts solely export cost from export revenue to determine net export benefits. Instead, the company asserts that it "calculates the inter-regional dispatch benefits the same as Staff's recommendation."[4]

This is in direct conflict with the Company's response to Staff DR 46, asking about the costing of the same resources. There, the Company states that they bid resources into the EIM at cost, with some adders. Hydro facilities sometimes receive a

[3] CUB Exhibit 201.
[4] UE 307 PAC/400/Dickman/69.

volatility adder, along with a ten percent adder. Coal resources are bid in with a ten percent adder.

> The 10 percent adder was approved by FERC in September 2006 and is intended to cover miscellaneous costs not otherwise incorporated in the DEB price. Examples of such costs include the risk of a forced outage, the differential between the California Independent System Operator's (CAISO) regional gas index and actual gas prices, and the cost of gas imbalance or penalties.[5]

So, of course, the bids may be *based* on resource cost. But, they are cost-plus. Adders are not necessarily costs that the Company incurs, and definitely don't belong in power costs since things like forced outages are already calculated into the Company's NPC forecast. The bids are not equal to resource cost, as the Company claims.

> The cost of each individual resource is equal to its EIM energy bid into the market, which represents the variable operating cost for that unit for a given period and generator configuration.[6]

A ten percent (or in the case of Hydro, twenty percent, 20%)[7] adder has real consequences. For one, the process that PacifiCorp uses to determine power costs becomes more opaque. In addition, customers pay costs beyond those required to operate their resources to meet load. To compound that, CAISO has had experience with strategic bidding, and abuse of market power[8] a concern of parties when the Company proposed entry into the EIM. Bidding in resources above cost has immediate implications for PAC customers. First, it restricts transacted supply. See the following table.

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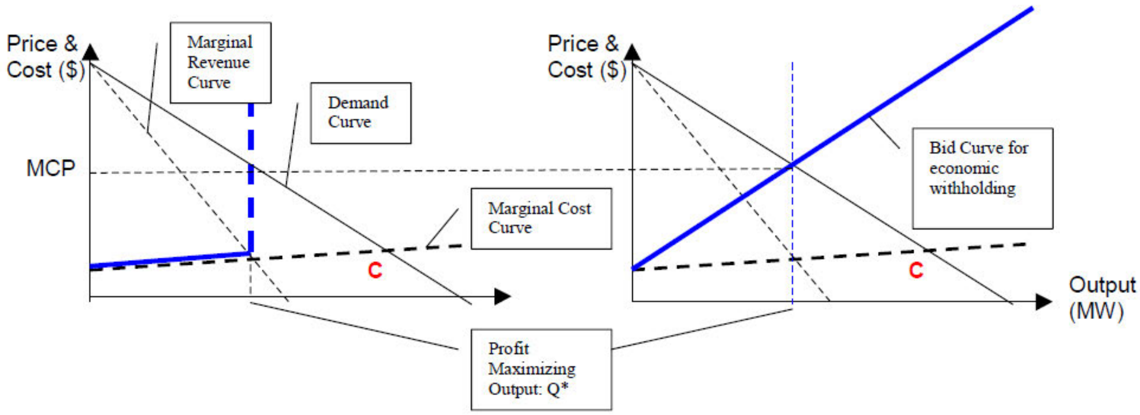
[5] CUB Exhibit 202.
[6] PAC/400/Dickman/69.
[7] CUB Exhibit 203.
[8] https://www.caiso.com/Documents/EmpiricalEvidence-StrategicBiddinginCaliforniaISORealTimeMarket.pdf.

[9]



For an oligopolist in the market facing a residual demand curve, it has two bidding strategies available: physical withholding (left panel) and economic withholding (right panel). Both strategies result in the same reduced output available to the market and at prices inflated above competitive levels. The expected competitive production and price levels are at the point marked "C".

The low dispatch of the Company's resources is one of the contentious issues in this case, with some plants teetering on minimum levels. Although the per unit revenue is higher, the plant is dispatching less. If the Company is keeping revenues below the bid price then the customers are losing double; both in volume and revenue.

Parties have exhibited clear interest in understanding the details of how the Company participates in the EIM and how that participation is subsequently treated in NPC. The Company, however, has obfuscated the process and tried to simplify explanations to parties. This has the effect of not just watering down the story, but actually changing. This is not helpful to the process.

[9] https://www.caiso.com/Documents/EmpiricalEvidence-StrategicBiddinginCaliforniaISORealTimeMarket.pdf.

B. Lack of Compliance with the UE 296 order

The Company admits that in Order 15-394 the Commission "directed the Company to work with the parties to assist their understanding and review of the system balancing transaction adjustment."[10] The Company seems to view this directive as merely meeting its minimum obligations in any standard power cost docket. If that was the case, the Commission need not put it explicitly in the order. The Company lists the GRID facilitation and workshops that it held with Staff,[11] but did not notify CUB of these workshops. CUB did tour the trade floor on June 20th and discuss concerns about EIM and DA-RT. However, this did not include any GRID access or demonstration.

The Company also admits that Commissioner Bloom requested a Commissioner workshop "after the parties completed their review of the Company's modeling in the TAM." However, the Company took the liberty of redefining "after the parties completed their review of the Company's modeling in the TAM" as "after [the Commission] issues its final order in this docket."[12] This approach offers little help to this docket and delays each party's opportunity to fully explore the implications of the DA-RT until next year's TAM. The Company has not even scheduled the Commissioner workshop that Commission Bloom requested. Moreover, it makes absolutely no sense that the Commissioners would want the benefit of parties' insight, recommendations, and review after their Order is issued. At that point, a workshop would have no effect.

In short, the Company has not demonstrated that they have done anything beyond what other utilities— namely PGE—would do in a normal power cost docket, even

[10] UE 307/PAC/400/Dickman/2.
[11] UE 307/PAC/400/Dickman/15.
[12] UE 307/PAC/400/Dickman/16.

though the Commission explicitly asked PacifiCorp to commit additional resources to party understanding and review.

C. The Company's "Expectation" of PURPA Facilities

CUB rejects the assertion that an expectation is equivalent to a forecast. In the case of PURPA facilities, the only input into the Company's expectation is the existence of a contract. However, the Company continues to insist that PURPA laws are clear, and that CUB's argument undermines "PURPA's cost recovery mandate."[13] CUB understands that the Company may be required to accept the contracts, but observes that there is a positive probability that these contracts may either expire without renewal or not materialize. In fact, in the course of this short docket, several QF suppliers have terminated their contracts with the Company, and the Company has had to reset its expectations for 2017.[14] In this light, CUB sought to understand the PURPA mandates that the Company was subject to in each state. In its DR 66, CUB asked that the Company "provide the applicable PURPA laws and rules for each state in which PacifiCorp operates."[15] The Company outright denied this request, stating that:

> The Company objects to this request as unduly burdensome, overly broad, not reasonably calculated to lead to the discovery of admissible evidence. Applicable Public Utility Regulatory Policies Act laws and rules for each state in which PacifiCorp operates are publically available.[16]

PacifiCorp is a multistate utility. Each state sets its own rules for PURPA contracts. Because those rules and contracts implicate power costs to Oregon customers, it is a reasonable place for discovery. In future cases, will PacifiCorp claim that because

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[13] UE 307/PAC/400/Dickman/84.
[14] UE 307/PAC/400/Dickman/11.
[15] CUB Exhibit 204.
[16] CUB Exhibit 204.

CAISO documents are publically available, that they will offer no help to parties in sorting out CAISO rules related to EIM or a regional ISO? The logic is the same.

D. Attempt to Assess CAISO Export Costs

The Company admonished Staff for attempting to verify the CAISO export costs by comparing "data from two different time periods," when Staff used last year's production costs to compare with the Company's EIM bids in this 2017 TAM. CUB looked at the same data as Staff, for a very obvious reason. In its filing, the Company does not provide the average per unit cost of its generation resources. This should be a set of data points that is not only included with the filing, but also readily available—not buried in hundreds of spreadsheets in some obscure column and row. Therefore, Staff looked at the most recent available data. Given that Staff challenged the Company on the cost of resources in the EIM stack, the Company should not merely *assert* that it calculates benefits using the generation cost of the resources:

> The Company's calculated benefits are consistent with Staff's recommendation and no additional adjustment is needed.[17]

It should *demonstrate* that the costs used in the calculation are the same as the unit cost of production for the individual unit in GRID.

E. Obfuscation and Lack of Cooperation in a Short Time Frame

CUB argues that, for PacifiCorp, the annual power cost docket has become incredibly complicated and that lack of cooperation between parties makes it an unproductive docket. Therefore, a simplified approach may be preferred—even at the cost of some regulatory lag. Quite simply, when the Company files such a voluminous

[17] UE 307/PAC/400/Dickman/73.

docket, and stalls and pivots in response to party inquiry, it essentially starts its game with 50 points already on the scoreboard, and dribbles in the corner to run out the clock.

IV. EIM Benefit Calculations

A. Transmission utilization factor

CUB took issue with the Company's discount of export benefits in the TAM forecast. The Company does not provide any documentation to demonstrate that CUB misunderstands the Company's calculation. CUB does not misunderstand. CUB understands, and the Company admits, that transmission utilization is not a factor in calculating historical benefits.[18] In fact, the Company asked CUB about this in a data request.[19] Since the forecast of EIM benefits that is at issue, CUB takes issue with the fact that *forecasted* benefits are being discounted by historical transmission utilization. The Company misrepresents CUB's argument:

> CUB argues that the Company improperly discounts inter-regional EIM benefits by applying a transmission utilization factor that unreasonably limits the actual benefits **realized** by the Company based on purported transmission constraints between PacifiCorp and the CAISO.[20]

This is incorrect. CUB believes that the Company records exports as they occurred within the existing transmission constraints—transmission constraints that the Company endogenously chose. The Company calls them (Mid-C to COB transmission left open MWh). CUB does not contend that the Company discounts historical benefits by transmission utilization, but that it discounts *forecasted* benefits. In both CUB Exhibit 108 (taken directly from the Company's initial filing) and CUB Confidential Exhibit 206

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[18] PAC/400/Dickman/76.
[19] UE 307 CUB Exhibit 205.
[20] UE 307/PAC/400/Dickman/76 (emphasis added).

which was provided by the Company in its reply filing,[21] the Company calculates prospective benefits from exports by taking historical exports, which were already subject to transmission availability and then discounts them by transmission expected to be available. CUB addressed this issue in its opening testimony. The Company asserted that CUB misunderstands, but failed to address CUB's point which concerned discounting forecasted benefits, not discounting actual benefits.

The Company, however, describes CUB's exact concern:

> Even if transmission is available for the EIM, actual historical data shows that not all of the capacity is used to support exports from the Company to the CAISO. In order to apply the historical export benefits to the 2017 forecast, the actual benefits (undiscounted) are divided by the total transmission that was available for EIM during the historical period and expressed in dollars per MWh of available transmission. This margin is then applied to the transmission in the 2017 TAM that is available for EIM. This approach ensures the transmission constraints are recognized and that transmission capacity is not utilized both for sales to the COB market and EIM.[22]

Therefore, the actual data records only actual exports that took place—if it was executed. That is, if it was economic to CAISO *and* it was not restricted by transmission constraints. Embedded in that number, by necessity, are transmission constraints. So the Company has that data. In the table below, CUB has removed all confidential data (all the data, in fact), but uses the Company's workpapers to highlight the fact that it is indeed calculating the amount utilized of the total transmission that the Company **made available to CAISO**. This could be more accurately called "allocated transmission utilization". In other words, if CAISO used all the transmission that PacifiCorp made available for the EIM, there would be no discount factor. However, in recent history if CAISO has used half of the transmission capacity that PacifiCorp made available, that

[21] CUB CONF Exhibit 206.
[22] PAC/400/Dickman/77.

transmission utilization factor would be half. In the spreadsheet below[23], the Company uses the shoulder and winter months to construct the transmission utilization factor (as evidenced by the boxes around the cells). In the summer, the Company calculates a different transmission utilization factor.

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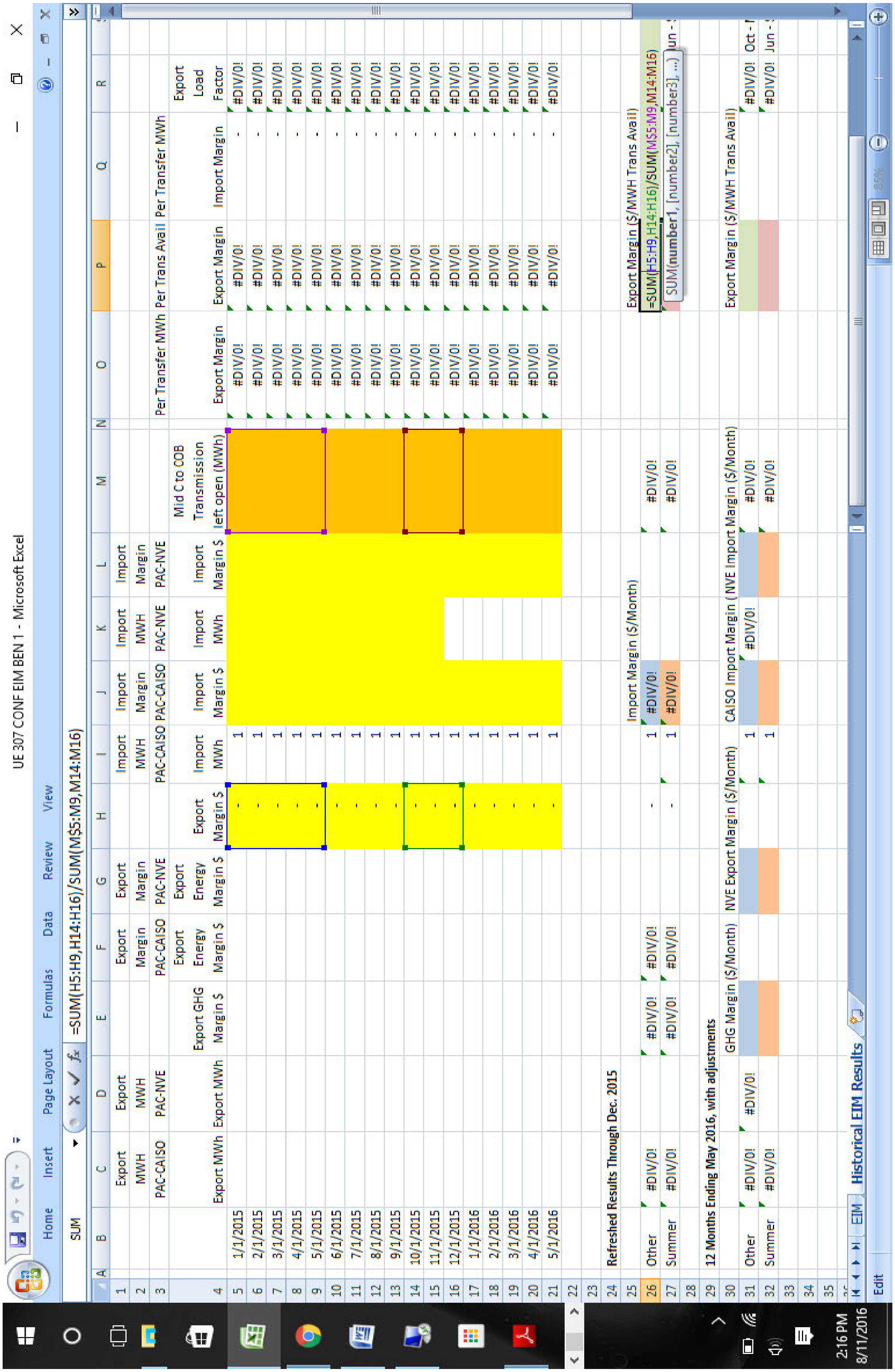
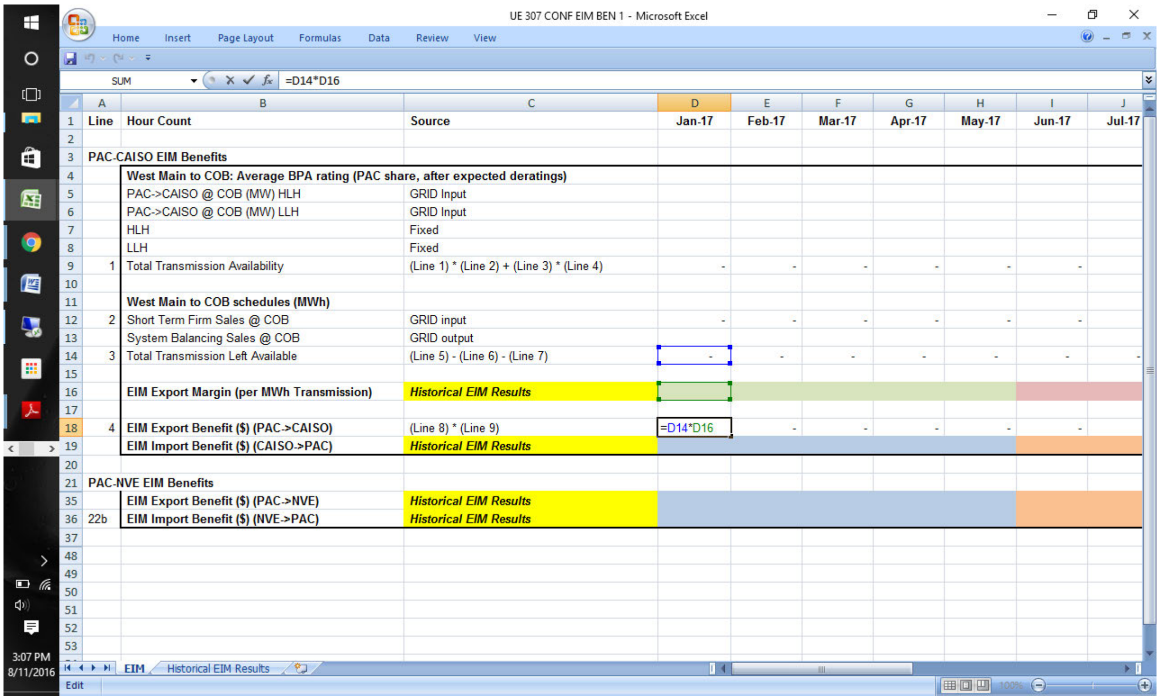
[23] CUB CONF Exhibit 207.


UE 307 CONF EIM BEN 1 - Microsoft Excel
Home
Insert
Page Layout
Formulas
Data
Review
View
SUM
=SUM(H5:H9,H14:H16)/SUM(M$5:M9,M14:M16)
Export MWH PAC-CAISO
Export MWH PAC-NVE
Export Margin PAC-CAISO
Export Margin PAC-NVE
Import MWH PAC-CAISO
Import Margin PAC-CAISO
Import MWH PAC-NVE
Import Margin PAC-NVE
Export MWh
Export MWh
Export GHG Margin $
Export Energy Margin $
Export Energy Margin $
Export Margin $
Import MWh
Import Margin $
Import MWh
Import Margin $
Mid C to COB Transmission left open (MWh)
Per Transfer MWh
Export Margin
Per Trans Avail
Export Margin
Per Transfer MWh
Import Margin
Export Load Factor
1/1/2015
2/1/2015
3/1/2015
4/1/2015
5/1/2015
6/1/2015
7/1/2015
8/1/2015
9/1/2015
10/1/2015
11/1/2015
12/1/2015
1/1/2016
2/1/2016
3/1/2016
4/1/2016
5/1/2016
#DIV/0!
Refreshed Results Through Dec. 2015
Other
Summer
Import Margin ($/Month)
Export Margin ($/MWH Trans Avail)
=SUM(H5:H9,H14:H16)/SUM(M$5:M9,M14:M16)
SUM(number1, [number2], [number3], ...)
12 Months Ending May 2016, with adjustments
GHG Margin ($/Month)
NVE Export Margin ($/Month)
CAISO Import Margin ($/Month)
NVE Import Margin ($/Month)
Export Margin ($/MWH Trans Avail)
Oct -
Jun -
EIM
Historical EIM Results
Edit
85%
2:16 PM
8/11/2016

Then, the question is, what does the Company do with this?



UE 307 CONF EIM BEN 1 - Microsoft Excel

SUM =D14*D16

	A	B	C	D	E	F	G	H	I	J
1	Line	Hour Count	Source	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17
2										
3	PAC-CAISO EIM Benefits									
4		West Main to COB: Average BPA rating (PAC share, after expected deratings)								
5		PAC->CAISO @ COB (MW) HLH	GRID Input							
6		PAC->CAISO @ COB (MW) LLH	GRID Input							
7		HLH	Fixed							
8		LLH	Fixed							
9	1	Total Transmission Availability	(Line 1) * (Line 2) + (Line 3) * (Line 4)	-	-	-	-	-	-	
10										
11		West Main to COB schedules (MWh)								
12	2	Short Term Firm Sales @ COB	GRID input	-	-	-	-	-	-	
13		System Balancing Sales @ COB	GRID output							
14	3	Total Transmission Left Available	(Line 5) - (Line 6) - (Line 7)	-	-	-	-	-	-	-
15										
16		EIM Export Margin (per MWh Transmission)	*Historical EIM Results*							
17										
18	4	EIM Export Benefit ($) (PAC->CAISO)	(Line 8) * (Line 9)	=D14*D16	-	-	-	-	-	
19		EIM Import Benefit ($) (CAISO->PAC)	*Historical EIM Results*							
20										
21	PAC-NVE EIM Benefits									
35		EIM Export Benefit ($) (PAC->NVE)	*Historical EIM Results*							
36	22b	EIM Import Benefit ($) (NVE->PAC)	*Historical EIM Results*							

EIM | Historical EIM Results

Here, in the 2017 forecast[24], it is clear that the Company is taking the same value from the prior spreadsheet (EIM Export margin (per MWh Transmission)) and multiplying it by the Company's own forecasted EIM exports.

It works like this. If, in one year, the Company received $3000, or on average $20/MWh for the 150 MWh that it exported to CAISO, then one would think that the next year, if 100 MWh were forecast to be exported to CAISO, that the Company would expect export revenue of $20/MWh x 100 MWh or $2000. Instead, the Company does the following. It looks at the fact that on average it made 300 MWh of *transmission* available to CAISO, so now, instead of calculating the revenue from the CAISO exported generation, the Company re-states the export revenue in terms of transmission and

[24] CUB CONF Exhibit 206.

concludes that, on average, the Company earned $3000/300 MWh of transmission or $10/MWh of transmission, instantly cutting the value of the CAISO export in half. Then the Company takes the same 100 MWh that it forecasted to be exported to CAISO, and multiplies it by $10/MWh. So, we have now $100 MWh x $10/MWh of transmission. The Company then concludes that $1000 is the appropriate export forecast. There are obvious problems with this. First, the numerator and the denominator do not cancel, because the numerator is exported energy, and the denominator is transmission. Second, to follow the Company's logic, one has to believe that PacifiCorp is exporting transmission to the EIM.

This is not appropriate. Transmission capacity may be a factor if the Company submitted generation to CAISO, and CAISO could not dispatch it due to transmission, but CAISO requires the Company to provide a base schedule that specifies generation and transmission. Transmission might also be a factor if the Company was building an econometric model, but it is not. After using historicals, the Company inserts a discount factor for the forecast. It is also disconcerting that the Company uses this treatment for PAC→CAISO exports, but not PAC→NVE (as evidenced by straight use of EIM historicals above) or any imports—either NVE→PAC or CAISO→PAC. Finally, consider the following: if this year, the Company submitted half of its remaining available transmission to CAISO (after its load was balanced at the hour) and CAISO executed exactly the same amount of exports from PacifiCorp to CAISO, the transmission utilization would double. Just because the Company decides to dump all leftover transmission on CAISO (and the Company decides how much to purchase in the first place), does not justify diluting the export benefit forecast for customers.

To correct this, the Company must remove the discount factor. The best forecast basis for EIM benefits should not just be based on historical data, but it should use the historical data in pure form without additional discounts.

B. Opportunity Cost as an Export Cost

In its Opening Testimony, CUB introduced a concern that the Company used opportunity costs in calculating the net benefits for EIM. CUB provided exhibits from the Company workpapers where opportunity costs were included. Instead of providing a demonstration of how it calculates the costs of exports to the EIM in its reply testimony, the Company just asserts that CUB is incorrect in its understanding:

> I agree with CUB that the opportunity cost of transacting at the COB market should not be subtracted from the inter-regional EIM benefits. In fact, the Company did not do so.[25]

This is becoming a tiresome theme, that Staff and CUB misunderstand the Company's approach. The Company asserts this to be true, and that is all that is needed.

It is nearly impossible for parties to gain a better understanding when the explanations provided are misrepresentations and the data is unavailable. In response to the opportunity cost issue and how export costs are calculated, the Company excuses itself from providing the data to parties so that they could confirm the cost of resources used in calculation.

> Because the data has become so voluminous, the calculation was transitioned to a database with summary reporting on a monthly basis. In an effort to show the details of the calculation, the Company provided a pricing example for a single interval demonstrating that the benefits are the net of revenue received less the variable costs incurred. Confidential Table 3 above also shows a summary of the benefits calculation for exports from PacifiCorp to the CAISO, demonstrating that the inter-regional benefits are equal to revenue received less the cost of generation

[25] PAC/400/Dickman/74.

> supporting transfers, and that the cost of generation from 2015 is in line with the production costs included in the 2017 TAM.[26] [internal citations excluded]

C. CAISO vs. PAC

The above sub-sections addressed why the Company's reply testimony did not resolve substantive issues raised in parties' opening testimony, nor did it provide parties with the means to resolve those issues. In this section, we compare CAISO's estimate with the Company's revised estimate, which doesn't accommodate CAISO's most recent benefits report published prior to the Company's reply testimony. The Company gained more experience, both with CAISO and NV Energy. Actual experienced benefits forced the Company to revise its estimates. In addition, the Company revised its methodology for EIM export benefits between the initial filing and reply testimony. In the Company's initial filing, it discounted export benefits PAC →NVE in the same way that it discounts PAC→CAISO, with the historical usage beta. In the reply filing, the Company altered its methodology so that export benefits PAC to NVE flow through without a transmission discount.[27] Why would the methodology be different for the two different regions to which PacifiCorp exports through the EIM?

In the Company's reply testimony, it increased forecasted EIM benefits of the *next* twelve months. See the table on the following page.

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[26] PAC/400/Dickman/75.
[27] CUB CONF Exhibit 206 (reply) and CUB CONF Exhibit 208 (initial filing).

Table 2
Total-Company EIM-Related Benefits and Costs

$ millions	2017 TAM - Direct	2017 TAM - Reply
Inter-regional dispatch - Exports	$10.2	$13.9
Inter-regional dispatch - Imports	$1.2	$5.3
Flexibility Reserves	$2.6	$4.5
Test-period EIM benefits	**$13.9**	**$23.7**
Test-period EIM costs	**$6.4**	**$6.2**

CAISO also released 2016 Q2 numbers for the *prior* twelve months.[28,29,30,31,32,33,34]

CAISO benefits report	2014 Q4	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1	2016 Q2	12 mo total
PACE	2.31	2.63	3.26	4.51				
PACW	2.42	1.19	4.46	4.01				
PAC Total	4.73	3.82	7.72	8.52	6.17	10.85	10.51	36.05

Even if benefits completely flat-lined today onward, PAC's estimates would be approximately 13 million below CAISO, the independent, unbiased operator. In other words, CAISO's record of current annual benefits is 50 percent higher than PAC's estimate of next year's benefits when there are even more participants bringing more

[28] http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ4_2014.pdf pg 5.
[29] https://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ1_2015.pdf pg 5.
[30] http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ2_2015.pdf pg 5.
[31] http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ3_2015.pdf pg 4.
[32] https://www.caiso.com/Documents/ISO_EIMBenefitsReportQ4_2015.pdf pg 4.
[33] https://www.caiso.com/Documents/ISO_EIM_BenefitsReportQ1_2016.pdf pg 4.
[34] http://www.caiso.com/Documents/ISO-EIMBenefitsReportQ2_2016.pdf pg 4.

diversity to the table. CUB's own estimates put potential 2017 benefits between $40 and $56 million if growth trends are considered.[35]

There is a lot of confusion surrounding EIM benefits. What is the quantification of the intra-regional benefits? Do those overlap with the DA-RT adjustment? How does the EIM dispatch PAC's low cost resources in fluctuating situations with and without congestion? How exactly does the Company cost resources when calculating benefit from exports? Can the Company demonstrate that this is the same way it costs resources for PAC customers? How does the Company construct a bid? The following data response offers a sense of the confusion[36]:

Excerpt from CUB Data Request 70

CUB reads Staff's testimony to say that the Company uses the Bid Price to calculate export costs.

Please provide a formula for EIM net benefits, explicitly detailing: (1) import avoided cost calculation (2) import cost calculation (3) export revenue calculation and (4) export cost calculation.

PAC's Response to CUB Data Request 70

Energy imbalance market (EIM) Benefits = Import avoided cost + Export margin

Import avoided cost = Import cost – Avoided cost to generate

Import cost = (15-Minute Market (FMM) transfer price * FMM volume) + (Real Time Dispatch (RTD) transfer price * (RTD volume – FMM volume))

FMM transfer price = (PacifiCorp FMM LMP + Adjacent BAA FMM LMP)/2

RTD transfer price = (PacifiCorp RTD LMP + Adjacent BAA RTD LMP)/2

Avoided cost to generate = RTD import volume * PacifiCorp cost to generate (dollars per megawatt-hour ($/MWh)

Export margin = Export revenue – Export cost to generate

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[35] CUB exhibit 209.
[36] CUB Exhibit 210.

Export revenue = (FMM * FMM volume) + (RTD transfer price * (RTD volume – FMM volume))

Export cost to generate = RTD export volume * PacifiCorp cost to generate ($/MWh)

PacifiCorp cost to generate = starting point in the daily resource stack equal to RTD LMP in PACE and FMM LMP in PACW, which determines the marginal unit for the interval. Once the marginal unit is identified, the cost to generate is determined by moving up the resource stack, multiplying each generator's cost (i.e. bid) by available capacity until the total transfer quantity is reached.

But this does not tell how EIM benefits are forecast for 2017, it deals with historical results. Where is the transmission discount? Where do the ten percent cost adders that the Company delineates in CUB Exhibit DR 71 show up?[37]

<u>PAC Response to CUB Data Request 71:</u>

As of December 1, 2015, with the joining of NV Energy into the energy imbalance market (EIM), PacifiCorp is required by the Federal Energy Regulatory Commission (FERC) to bid in its resources at or below the Default Energy Bids (DEB) of each resource.

The DEB calculation for PacifiCorp's participating natural gas resources utilizes daily natural gas price based on the average of four regional gas indices, a units heat rate, variable operation and maintenance (O&M) and a 10 percent adder. The DEB is updated on a daily basis for natural gas prices.

The DEB calculation for PacifiCorp's participating coal fired resources is the coal fuel cost times the heat rate plus variable O&M **and a 10 percent adder**. All variables are updated as needed to reflect accurate fuel costs, taking into consideration taxes, transport adjustments, quality and contract specifications.

The DEB calculation for PacifiCorp's participating hydro resources is the maximum of Intercontinental Exchange (ICE) indices for the Mid-Columbia (Mid-C) heavy load hour (HLH) plus a volatility adder **plus a 10 percent adder**. This calculation is updated daily with the current ICE index prices.

The 10 percent adder was approved by FERC in September 2006 and is intended to cover miscellaneous costs not otherwise incorporated in the DEB price. Examples of such costs include the risk of a forced outage, the differential between the California Independent System Operator's (CAISO) regional gas index and actual gas prices, and the cost of gas imbalance or **penalties**.

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[37] CUB Exhibit 203.

But how does that sync with the Company's statement that these bids are equal to cost:

> The cost of each individual resource is equal to its EIM energy bid into the market, which represents the variable operating cost for that unit for a given period and generator configuration.[38]

Does that mean that customer costs normally include penalties that the Company incurs for violations, and adders for things that are already included in the Company's operations?

D. Intra-regional Benefits

In Opening Testimony, CUB argued that the Company shortchanged its customers by not crediting NPC for EIM intra-regional benefits. CUB maintains that position, and has seen no evidence from the Company that GRID calculates all the benefits that the EIM generates. In particular, the Company asserts that GRID is perfectly optimized, yet it only operates down to the hour. Sub- hourly transactions are facilitated by the EIM and therefore offer opportunities for efficiencies. For example, because the EIM collects 15 minute data and dispatches economically every 15 minutes, it has the capability to prepare for economic ramping. The Company, in GRID sets dispatch equal for all five minutes across the hour, while actual operations often require them to be different. Since the EIM can dispatch the Company's own plants automatically and economically across the hour, while ramping them to meet the next hour, efficiencies may be gained. Additionally, even if PacifiCorp had the generation in the West to meet East loads (or vice versa), sometimes transmission constraints, absent

[38] PAC/400/Dickman/69.

EIM, would not allow these resources to be utilized. PacifiCorp's resources can now flow through the network of the EIM. How would these efficiencies be treated?

The Company presents, as its evidence that intra-regional benefits need not be incorporated, NVE's situation:

> The results of NVE's participation in the EIM provide additional evidence that the intra-regional benefits are captured in GRID and that EIM helps bring actual operations into alignment with the perfect optimization used in the GRID model. Unlike PacifiCorp, prior to joining EIM, NVE already utilized a computerized security constrained dispatch model to dispatch its resources in actual operations. Thus, its actual operations were already optimized prior to joining the EIM. In the CAISO's quarterly EIM benefit report for the first quarter of 2016, it states that the benefits realized by NVE's participation are mainly inter-regional transfer benefits. The report states that this "is attributed to NVE's optimization of its base schedules prior to submission to the EIM.[39]

CUB allots no weight to this argument. The Company claims that CAISO conducts a different counterfactual assessment for NV energy because it previously had SCED. However, even if this is true, the automated dispatch, and optimal communication between plants and balancing authorities below the hour are efficiencies afforded specifically by the EIM investments and participation. The Company has merely asserted, done nothing to demonstrate that GRID produces efficient sub-hourly results when load, generation and transmission are allowed to vary within the hour. Therefore, ignoring calculated intra-regional benefits is inappropriate.

E. CUB's Proposal: Use Actual Results

For these reasons, CUB recommends that for EIM benefits forecast in the TAM, the Company use actual benefits **as reported by CAISO** from the current year. In this case, there have been multiple methods: the Company's method, the Company's method

[39] PAC/400/Dickman/62.

with adjustments proposed by Staff and CUB, and CAISO actuals with growth included for new entrants, amongst others. Using current year CAISO actuals is simple, moderate, and more verifiable than the method that the Company proposed. Clearly, customers will not get the advantage of annual growth of benefits, until the following year. However, what is lost there will be gained in transparency and unbiased-ness. The Company clearly has an incentive to under-forecast EIM benefits. To date, parties have been unable to decipher, and the Company has been unwilling to demonstrate, exactly how, and with what data, EIM benefits are calculated. CAISO on the other hand, does not have an incentive to miscalculate participant benefits. Moreover, when the steady-state is achieved and all participants have entered, benefits should stabilize so that the prior year actuals will be a very good indicator of the test year benefits.

V. DA-RT adjustments

The Company asserts, without support that:

> CUB argues that the Company's adjustment to add costs related to day-ahead and real time system balancing transactions reflect the costs of balancing the system that a perfectly optimized GRID model does not recognize. Therefore**, CUB reasons that the Company's adjustment for system balancing transactions effectively de-optimizes GRID** so that customers no longer receive the benefits of GRID's perfectly optimized dispatch.[40]

CUB does not argue that DA-RT de-optimizes. GRID is only optimal under the paradigm that it was built, and it is subject to the input entered. GRID optimizes an instantaneous system down to the granularity of one hour. It does not produce finer results than that. CUB points out that part of GRID's inability to produce accurate results is the fact that GRID is instantaneous—compared to real operations which are

[40] PAC/400/Dickman/64 (emphasis added).

sequential—and that the Company faces different price curves a month ahead, a week ahead, an hour ahead, etc. The Company does not disagree with this fact.

The DA-RT manipulation involves two components: historical volumes and historical prices. The Company uses both of these to construct a dollar amount that, with forecasted volumes, needs to be interpolated into the TAM forecast, so it allocates this dollar amount across the forecasted GRID transactions. CUB also points out that some of these volumes and therefore dollar amounts are pre-EIM, and therefore they are spread across a structural break.

The Company then submits a new argument:

> Participation in the EIM requires the Company to submit balanced base schedules 55 minutes prior to the hour. Thus, under the EIM, market purchases and sales must be executed at least 60 minutes in advance in order for the Company to present a balanced schedule at the 55-minute mark. Before the Company's participation in EIM, the Company was required to submit balanced base schedules 20 minutes before the hour and could therefore transact up to around 30 minutes before the hour. Because the EIM requires PacifiCorp to balance its system 60 minutes in advance, instead of 30 minutes, there is more uncertainty, and both the Company and its counterparties may be less willing to transact. If parties are less willing to transact, there will be higher prices for purchases because counterparties do not want to part with resources that might be needed. In addition, because other counterparties know of PacifiCorp's time limits for transactions, they make less competitive bids, knowing that even if PacifiCorp does not accept, they can sell to other counterparties closer to their 20 minute transmission scheduling deadline.[41]

The Company here argues that entrance into the EIM implicitly tied their hands to a cost—the cost that their usual trading partners are now gaming the system. The Company goes onto argue that now, purchases and sales with counter parties (sales for resale before the hour) will be less profitable than they were before. PacifiCorp is subject to market manipulation by other parties. CUB has several responses to this. First, in

[41] PAC/400/Dickman/35-36.

CUB's recollection, PacifiCorp stated at the June 20th PacifiCorp trade floor tour that a shift in its position can alter market prices, because of its large size and footprint. Second, CUB is not aware of PacifiCorp listing this as a potential cost of joining the EIM. Additionally, as more companies and states enter the EIM, this cost, if it is real, will diminish because other parties will be subject to the same restrictions as PAC in the EIM. Finally, concerning the DA-RT adjustment, pre-EIM all companies have the opportunity to submit inflated costs to the market for trade, and therefore, as the Company explains, it ended up paying higher prices when it bought and it received lower prices when it sold. However, the EIM, with its regulations on bids, and the fact that it divides the benefit of a transfer between the supplier and the importer, relieves the Company of gag pricing within the hour.

The Company attempts to portray CUB's argument against the four year DA-RT as an aversion to four years of data. This is incorrect. CUB's argument is that a change from what was understood to be a rolling average, to a DA-RT adjustment that is based on a cumulative average, is a modeling change. In power cost proceedings, if the Company changed from a 30 year rolling weather average to a 20 year rolling average (as has been done), this would be examined as a modeling change. CUB is concerned about this, because at the discussion that CUB had with the Company on June 20,[42] the Company confirmed that it now had many more years of data, going back much further than 2012, available. This data had not been available to the Company because of software and transition, last year, but now it is. Therefore, next year, the Company could base DA-RT on a 15 year average. CUB asks whether that makes sense, and whether it would be considered a modeling change. CUB's recommendation continues to be

[42] PAC/400/Dickman/16.

abolishment of the DA-RT. However, if it is allowed to continue, CUB would like clarity on the structure and limitations of the DA-RT in a way that is not malleable by the Company. CUB is not recommending a three year rolling average, a four year rolling average, or a fifteen year rolling average. CUB is concerned that the Company has a lot of data and gets to apply it differently in each TAM as a way to maximize the adjustment. The purchases that the Company must make to balance its system, and the premium it pays when it purchases additional volumes closer to the hour (and discount it receives when it sells closer to the hour) are spuriously correlated. They are both driven by the Company's alignment in diversity (or lack thereof) with the regional network in which it operates. When PacifiCorp needs to buy more power, often many other counter parties do as well, and the same goes for when it needs to unload power. Any modification to GRID, if at all, should identify that root cause and not consider all trades equally tainted. It is clear from the Company's testimony that when market volume is high, the price is also high, and when market volume is low, the price is also lower. This also may correlate with PacifiCorp’s system, which reaches capacity as market volume is high and has a lot of slack capacity when market volume is low. Given that the Company uses an average price throughout the month—and does not deploy GRID sequentially with multiple appropriate price curves corresponding to the proximity to the hour (which would be ideal)—the Company should use the data it has, which is its own production capacity and capacity factors to determine when the market prices that it will pay are above or below average.

VI. PURPA Facilities and Recovery

CUB objects to the Company including 100% of PURPA contracts in rates, which will likely over-forecast the cost of PURPA. This is specifically because (1) PacifiCorp does not have a perfect forecasting rate and (2) this would include solar facilities that take 2-3 months to build but are over a year away from deployment.

The Company claims that CUB already agreed to this methodology, because the 2011 TAM included a stipulation that allowed the Company to include contracts as of the Indicative Filing. According to the Order in the 2011 TAM:

> Pacific Power agrees to file an attestation with its Indicative Filing in this and in future TAM proceedings that will confirm that all contracts executed prior to the contract lockdown date have been included (or will identify any exceptions and the reasons why such contracts were excluded).[43]

CUB did support that stipulation in 2010 which related to all NPC contracts. However, evidence today demonstrates that this leads to over forecasting of QF contracts. Based on this evidence, CUB is proposing a change in how QF contracts are forecast.

CUB remains concerned that the Company is including QF contracts in its forecast at their maximum level, when it is likely that some will not show up. A good analogy is Forced Outage Rates ("FOR"). Power plants have a projected capacity, but rather than forecast them to operate at that capacity, we de-rate their capacity factor because we know "stuff happens" and there will be times that they will not be operational, though we do not know when. Historic data is used to calculate this FOR. Because there is evidence that "stuff happens" and not all QFs are completed and operational as forecast, we should "de-rate" our QF forecast based on historical evidence.

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[43] OPUC Order No 10-363, page 4.

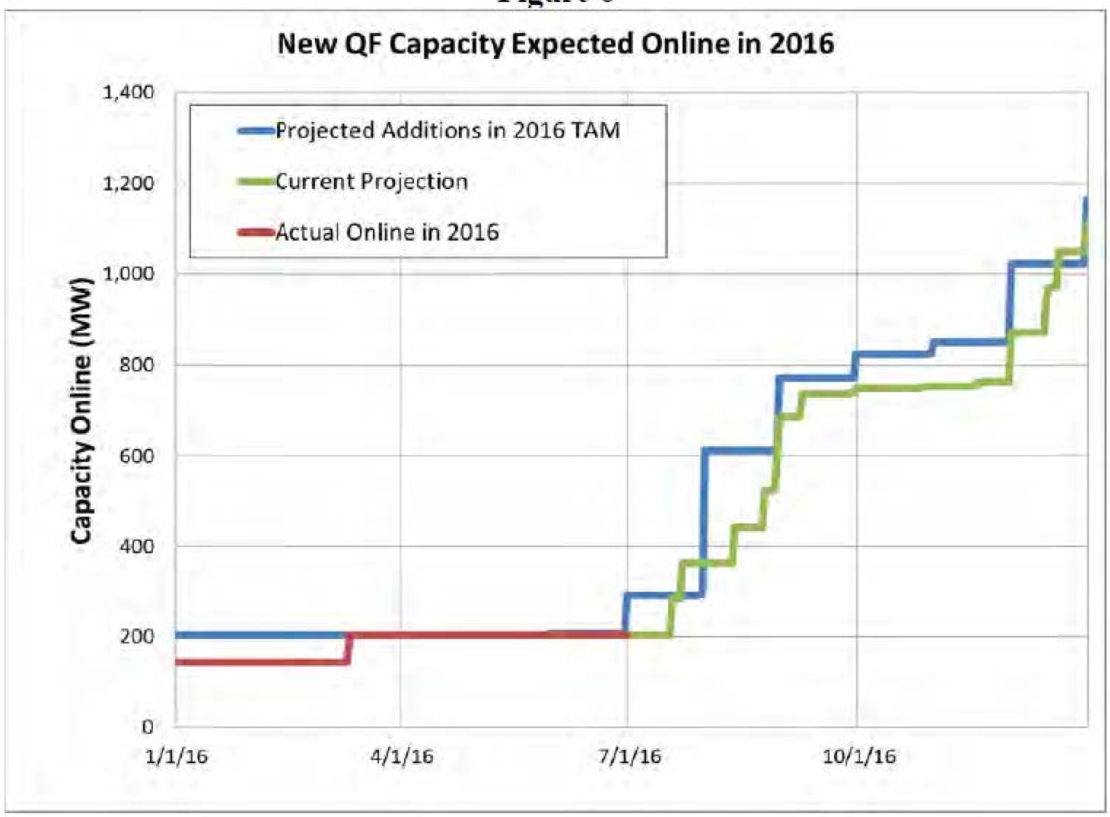
CUB believes the evidence does support an adjustment to the QF forecast. CUB asked the Company to provide historical forecast and actuals for QFs. The Company provided data that demonstrated it expected 1006 MW of solar to come online in the 2016 TAM period, with no commercial operation dates. However, it also shows that the Utah Red Hills Renewable Park 80 MW project is not commercial operational yet, even though it has been forecast into the 2015 TAM and the 2016 TAM.[44]

Actual Solar Qualifying Facility (QF) Projects - Calendar Year 2014 through Calendar Year 2016					
Project Owner	**Project Name**	**Commercial Operation Date (COD)**	**Calendar Year 2014**	**Calendar Year 2015**	**Calendar Year 2016**
			2014 TAM (UE-264)	**2015 TAM (UE-287)**	**2016 TAM (UE-296)**
eBay	eBay Solar	1/30/2014	0.52	0.52	0.52
SunEdison	South Milford Solar	4/1/2015	Not Applicable	2.93	2.93
SunEdison	Laho Solar	7/14/2015	Not Applicable	3.00	3.00
SunEdison	Milford Flat Solar	7/23/2015	Not Applicable	3.00	3.00
SunEdison	Granite Peak Solar	8/21/2015	Not Applicable	3.00	3.00
SunEdison	Beryl Solar	8/24/2015	Not Applicable	3.00	3.00
SunEdison	Fiddler's Canyon 1	9/22/2015	Not Applicable	3.00	3.00
SunEdison	Fiddler's Canyon 2	9/22/2015	Not Applicable	3.00	3.00
SunEdison	Greenville Solar	10/29/2015	Not Applicable	2.19	2.19
SunEdison	Cedar Valley Solar	12/7/2015	Not Applicable	3.00	3.00
SunEdison	Fiddler's Canyon 3	12/21/2015	Not Applicable	3.00	3.00
SunEdison	Milford 2 SOlar	12/21/2015	Not Applicable	2.97	2.97
SunEdison	Buckhorn Solar	12/23/2015	Not Applicable	3.00	3.00
Juwi Solar	Pavant Solar	12/30/2015	Not Applicable	50.00	50.00
Scatec Solar	Utah Red Hills Renewable Park	Project has not been deemed commercially operational yet. Generating test energy	Not Applicable	80.00	80.00
Forecast			0.52	96.71	1,006.43
* There were no solar QF projects online prior to 2014.					

[44] CUB Exhibit 211.

In the Company's reply testimony, it addresses this inconsistency, by stating that the majority of this QF capacity has yet to come online this year and offering this graph of QF projects.[45]

Figure 6



This graph supports CUB's point. So far in 2016, actual QF capacity has been below forecast for at least part of the year. Only a small fraction of the total expected for the year had come on line by July. And in the remainder of the year, the current forecast is nearly always below the 2016 TAM forecast and of course, projects that are part of the "current forecast" (the green line) may or may not come online consistent with that current projection. Because 80% of the capacity forecast this year is not yet operational, about all we can conclude from this graph is that we know that the 2016 forecast was

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45 UE 307/PAC/400/Dickman/88.

greater than what is actually happening, but we do not know the magnitude of the difference. CUB remains concerned that with a declining market, solar developers have an incentive to postpone construction to take advantage of technological advancements. Couple that with the fact that the Company's QF contracts are structured, so that the majority of them come online at the end of the year and, while litigating the current TAM docket, parties and the Company are unable to discern whether their PURPA facilities placed into rates from the last year are in fact going to be online in the current year. This means that to look a year and a half out, with no information from the current year, parties are left hamstrung at best. In Opening Testimony, CUB, based on the information provided by the Company saw that almost none of the PURPA facilities forecasted for this year had actually come online. Therefore, CUB recommended that the Company place in rates only those that could be verified. The Company now states that those PURPA facilities will still come online this year, and from the graph, it seems that the majority of them are scheduled to come online before the conclusion of this case.

A. CUB’s Recommendation

CUB recommends that the Company include, in rates, all existing facilities (excluding those for which the Company is in knowledge of plans for cessation of operations) and those which have signed contracts. However, these signed contracts should be discounted for the historical inaccuracy of the Company's forecast. Specifically, CUB proposes that the Company compare the forecasted and actual energy from new QFs in each of the most recent 3 years with a full year of data and use this to identify a discount rate to apply to the forecast QF energy from new QF’s in the 2017 TAM.

VII. Coal

A. Take or Pay

In CUB's Opening Testimony, we recommended that any take or pay provisions associated with a contract signed after the 2013 IRP be removed from the model. PacifiCorp responded to CUB's concerns about recent take or pay coal contracts by suggesting that our adjustment would not make a difference:

> First, CUB's adjustment is inapplicable because none of the Company's coal contracts executed since the 2013 IRP were adjusted in this case to account for the minimum take requirements. Thus, the value of CUB's adjustment is zero.[46]

The problem with PacifiCorp's response is that its final modeling of power costs comes after the Order in this docket. After updating both forward price curves for gas and electricity and contracts, there is no way to know how individual resources will dispatch in the Fall. While the current power cost modeling methodology may show the plants dispatching at a level that does not require an adjustment to account for the take or pay minimums, it does not mean that the October Update will not require an adjustment. For this reason, CUB continues to recommend that PacifiCorp remove any impact from these post 2013 IRP take or pay contracts when it finalizes 2017 power costs.

B. Environmental retrofits

CUB notes that the Company accepts CUB's "proposed adjustment to remove the NPC impact of the selective catalytic reduction systems (SCR) investments at Jim Bridger Units 3 and 4.[47]

[46] UE 307/ PAC/400/Dickman/51-52.
[47] PAC/400/Dickman/7-8.

VIII. Conclusion

In conclusion, CUB notes that the 2017 TAM process has been less than ideal, and continues to be concerned over the Company's forecasting and accounting methods. In summary recommendation, CUB proposes that the Company flow through the same EIM benefits as reported by CAISO for the most recent available four quarters at rate effective date (this may mean Q4 2015, Q1 2016, Q2 2016, Q3, 2016). CUB proposes that new QF contracts should be forecasted into rates with a 'delay rate' discount taken from the last three years of data for plants that came online late. Finally, regarding take-or pay coal, CUB recommends that the Company exclude all take or pay impacts (implicit and explicit) from contracts that were signed after 2013, because prudency has not been established.

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July 25, 2016
CUB Data Request 72

CUB Data Request 72

CUB also asked about priority of resources served. The following is CUB's understanding:

The Company stated that the PAC customers get served with lowest cost resources as a priority. Then the Company submits resources to CAISO. CAISO then pulls the highest cost resources from the stack. CUB asked about what happened if the Company used low cost resources for PAC customers and CAISO picked off the top of the stack, leaving mid-cost resources unutilized. The Company stated that all resources from the resource just below CAISO market price down to the least expensive one would get utilized, and that the Company submitted all resources not used by customers to CAISO.

From Staff's testimony, CUB reads that the Company costs exports according to the bid price of the highest priced resource in the stack at the time.

Please reconcile the above seeming contradiction:

Does the Company always submit all resources above those needed to serve PAC customers?

(a) If so, what determines if those surplus resources are submitted to CAISO, or reserved for COB contracts. Please be explicit, and provide formulas used in making decisions.

Response to CUB Data Request 72

The energy imbalance market (EIM) is an intra-hour market that utilizes a base schedule submitted by PacifiCorp for how it will meet its load requirements and ancillary service obligations for each operating hour. Included in the base schedule that is submitted to the California Independent System Operator (CAISO) at 40 minutes prior to each operating hour, is the net interchange amount (imports and exports). The imports or exports that are scheduled prior to the hour include bilateral transactions, such as Mid-Columbia (Mid-C) purchases or sales. Bilateral purchases or sales are contracted for prior to the operation of EIM.

The CAISO security constrained economic dispatch model (SCED) is used to optimize PacifiCorp's participating generation resources relative to the forecast of the combined balancing authority area (BAA) – *CAISO + Nevada + PacifiCorp East (PACE) + PacifiCorp West (PACW)* – load and variable energy resources for each operating hour. PacifiCorp submits a bid for each of its participating resources that are scheduled on-line for each operating day. The CAISO real-time market optimization serves load by the most economic resource, drawn from the larger pool of resources, to most efficiently match load with supply while ensuring reliability.

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The SCED model used by the CAISO does not "pull" from the highest cost resource from the stack, it utilizes the marginal resource as the next available unit cost of generation or next available unit cost of decrement. Simplistically, the marginal resource is determined by the SCED as the least cost available capacity on the system. There could be additional units on-line that have higher operating costs, or higher in the stack resources, but if there are lower cost resources that have available capacity these units will set the locational marginal price and be used to determine the cost of the next megawatt (MW) produced.

PacifiCorp's statement that its lowest cost resources are used to serve its own load first, was a simplification of the CAISO SCED model optimized solution. Essentially, each EIM entity benefits by having its load served by the most economic resources, whether they be owned by PacifiCorp, Nevada Energy or a generator within the CAISO Balancing Authority Area subject to transmission and reliability constraints.

UE 307 / PacifiCorp
July 14, 2016
OPUC Data Request 46 – 1st Supplemental

OPUC Data Request 46

Regarding the Excel spreadsheet "ORTAM17w_EIM Benefits ORTAM17 (Jan15-Jan16) CONF" provided with TAM support set 2:

(a) Please provide supporting data for the values contained in all cells of the tab labeled "Transfers." These values have been supplied as entered values with no references or source citations. Please provide citations for data used as sources for these values.

(b) Please provide a report of all accounting transactions booked under FERC account 555 as itemized on the tab labelled "TORIS".

(c) Please provide documentation of SAP transactions contained in SAP accounts 508015 and 546516 that support values in the tab labelled "TORIS".

(d) Referring to the tab labelled "Historical EIM Results", please provide a narrative description of how the values in column D (labelled "Export GHG Margin $") are computed. Use references to specific cell locations and values contained within this workbook when applicable.

(e) Referring to the tab labelled "Historical EIM Results", please provide a narrative description of how the values in column E (labelled "Export Energy Margin $") are computed. Use references to specific cell locations and values contained within this workbook when applicable

1st Supplemental Response to OPUC Data Request 46

Further to the Company's response to OPUC Data Request 46 dated June 23, 2016, the Company provides the following supplemental response to subpart (e):

(e) Please refer to Confidential Attachment OPUC 46 -1 1st Supplemental, which provides the detailed results of the revised energy imbalance market (EIM) margin calculation, based on generators receiving a single dispatch instruction on a five-minute basis reflecting the net market result. Please refer to Confidential Attachment OPUC 46 -2 1st Supplemental, which provides the calculations supporting the net power costs (NPC) impact associated with this change.

Please refer to Confidential Attachment OPUC 46 -3 1st Supplemental, which provides an example demonstrating how the Company's incremental generation expense associated with EIM transfers is calculated. The example includes both the calculation used in the initial filing and the corrected calculation identified in the Company's original response to OPUC Data Request 46 subpart (e); for which detailed results are provided above.

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OPUC Data Request 46 – 1st Supplemental

The incremental generation expense reflected in the above analysis is derived from the EIM energy bids for each of the Company's resources. As of December 1, 2015, with the joining of NV Energy into the EIM, PacifiCorp is required by the Federal Energy Regulatory Commission (FERC) to bid in its resources at or below the Default Energy Bids (DEB) of each resource.

The DEB calculation for PacifiCorp's participating natural gas resources utilizes daily natural gas price based on the average of four regional gas indices, a units heat rate, variable operation and maintenance and a ten percent adder. The DEB is updated on a daily basis for natural gas prices.

The DEB calculation for PacifiCorp's participating coal fired resources is the coal fuel cost times the Heat rate plus variable operation and maintenance and a ten percent adder. All variables are updated as needed to reflect accurate fuel costs, taking into consideration taxes, transport adjustments, quality and contract specifications.

The DEB calculation for PacifiCorp's participating hydro resources is the maximum of Intercontinental Exchange (ICE) indices for the Mid-Columbia (Mid-C) heavy load hour (HLH) plus a volatility adder plus a 10 percent adder. This calculation is updated daily with the current ICE index prices.

The 10 percent adder was approved by FERC in September 2006 and is intended to cover miscellaneous costs not otherwise incorporated in the DEB price. Examples of such costs include the risk of a forced outage, the differential between the California Independent System Operator's (CAISO) regional gas index and actual gas prices, and the cost of gas imbalance or penalties. The FERC order is publicly available and can be accessed by utilizing the following website link:

FERC Docket ER06-615-000, page 284. September 21, 2006.
https://www.ferc.gov/whats-new/comm-meet/092106/E-1.pdf

PacifiCorp is currently bidding in its thermal resources consistent with the DEB to accurately reflect the operating cost of its units.

Resource operating requirements for hydro facilities requires PacifiCorp to provide the market a correct price signal that can be at or below the DEB. During high run-off conditions PacifiCorp may submit a bid for the hydro resources that reflect a lower incremental cost and allow the resource to be dispatched first and decremented last in the PacifiCorp stack of resources. During periods of normal hydro operations PacifiCorp maximizes its hydro resource bid to the DEB price.

The confidential attachments are designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

UE 307 / PacifiCorp
July 25, 2016
CUB Data Request 71

CUB Data Request 71

In opening testimony (UE 307/Staff/100/Crider/14-15), Staff describes the net benefit calculation of EIM. In particular, Staff describes the cost portion.

In conversation with the Company, CUB asked about net benefit calculations and understood that the Company took the following approach: The Company, for the 2017 TAM, receives a monthly report from CAISO regarding transfers, including volume, timing, and origin/destination. The Company then goes back and finds which plant was dispatched, and uses that generation cost to calculate the cost portion. The Company also stated that this was in contrast to how it was done last year, which was to use an average of plant costs. CUB reads Staff's testimony to say that the Company uses the Bid Price to calculate export costs.

Please explain how the Company calculates the bid price that it seems to use for costing exports.

Response to CUB Data Request 71

As of December 1, 2015, with the joining of NV Energy into the energy imbalance market (EIM), PacifiCorp is required by the Federal Energy Regulatory Commission (FERC) to bid in its resources at or below the Default Energy Bids (DEB) of each resource.

The DEB calculation for PacifiCorp's participating natural gas resources utilizes daily natural gas price based on the average of four regional gas indices, a units heat rate, variable operation and maintenance (O&M) and a 10 percent adder. The DEB is updated on a daily basis for natural gas prices.

The DEB calculation for PacifiCorp's participating coal fired resources is the coal fuel cost times the heat rate plus variable O&M and a 10 percent adder. All variables are updated as needed to reflect accurate fuel costs, taking into consideration taxes, transport adjustments, quality and contract specifications.

The DEB calculation for PacifiCorp's participating hydro resources is the maximum of IntercontinentalExchange (ICE) indices for the Mid-Columbia (Mid-C) heavy load hour (HLH) plus a volatility adder plus a 10 percent adder. This calculation is updated daily with the current ICE index prices.

The 10 percent adder was approved by FERC in September 2006 and is intended to cover miscellaneous costs not otherwise incorporated in the DEB price. Examples of such costs include the risk of a forced outage, the differential between the California Independent System Operator's (CAISO) regional gas index and actual gas prices, and the cost of gas imbalance or penalties. The FERC order is publicly available and can be accessed by utilizing the following website link:

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FERC Docket ER06-615-000, page 284. September 21, 2006.
https://www.ferc.gov/whats-new/comm-meet/092106/E-1.pdf

PacifiCorp is currently bidding in its thermal resources consistent with the DEB to accurately reflect the operating cost of its units.

Resource operating requirements for hydro facilities requires PacifiCorp to provide the market a correct price signal that can be at or below the DEB. During high run-off conditions, PacifiCorp may submit a bid for the hydro resources that reflect a lower incremental cost and allow the resource to be dispatched first and decremented last in the PacifiCorp stack of resources. During periods of normal hydro operations PacifiCorp maximizes its hydro resource bid to the DEB price.

UE 307 / PacifiCorp
July 20, 2016
CUB Data Request 66

CUB Data Request 66

Please provide the applicable PURPA laws and rules for each state in which PacifiCorp operates.

Response to CUB Data Request 66

The Company objects to this request as unduly burdensome, overly broad, not reasonably calculated to lead to the discovery of admissible evidence. Applicable Public Utility Regulatory Policies Act laws and rules for each state in which PacifiCorp operates are publically available.

UE 307 / CUB
July 19, 2016
PacifiCorp Data Request 1

PacifiCorp Data Request 1

Refer to CUB/100, McGovern/9. Please identify the specific take or pay contracts and provide calculations and workpapers quantifying the impact of the proposed adjustment based on the recommendation that the "costs and impacts of the most recent take or pay contracts should be disallowed."

Response to Data Request 1

Regarding the specific contracts, CUB refers to its opening testimony and CUB Exhibit 102. Take-or-pay contracts that were signed on or after 2013, have not been demonstrated to be prudent, given that the Company was aware or environmental cost risk. Therefore, customers should not be burdened with implicit or explicit costs arising from any take or pay contracts that were signed 2013 or later.

CUB did not make a recommendation on a particular dollar adjustment, and therefore does not have workpapers to support said dollar adjustment. CUB's understanding is that the Company's current approach is to run the model twice-once with the contracted price of coal, and once with the cost of coal at zero--to find out whether the minimum take threshold is economical to trigger. Then, the Company manually implements this level and the inferred price. CUB also understands that the Company takes this approach because GRID cannot handle two simultaneous fuel prices for the Coal plant. CUB believes that the Company's approach is a manual alternative to the GRID model. Hence, CUB's recommendation is not that the Company make a dollar adjustment to its forecast, but, rather, CUB recommends that the Company re-run GRID with the minimum of market cost of coal or the contract price, and allow the model to optimize. Then, the corresponding optimal output, along with other model components will determine NVPC. CUB further notes that the impact of this adjustment will change as the Company further updates its power cost forecasts as this docket goes forward.

UE 307 / CUB
July 19, 2016
PacifiCorp Data Request 2

PacifiCorp Data Request 2

Refer to CUB/100, McGovern/10. Please confirm that the 2017 Energy Imbalance Market (EIM) forecast of $6.4 million referenced on line 8, McGovern/10 represents EIM costs included in the TAM test period rather than EIM benefits (refer to Table 2 of PAC/100/Dickman/26).

Response to Data Request 2

CUB confirms that $6.4 million refers to the EIM costs and that gross EIM benefits are, as calculated by the Company, $13.9 million or as CUB reads EIM net benefits to be $7.5 million. Please refer to our forthcoming Errata Filing.

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PacifiCorp Data Request 3

PacifiCorp Data Request 3

Refer to CUB/100, McGovern/10. Does CUB agree that Table 2 of PAC/100, Dickman/26 shows the EIM benefits for the 2017 TAM to be $13.9 million, not the $6.4 million referenced on line 8, McGovern/10?

Response to Data Request 3

CUB confirms that $6.4 million refers to the EIM costs and that gross, EIM benefits are, as calculated by the Company, $13.9 million or as CUB reads EIM net benefits to be $7.5 million. Please refer to our forthcoming Errata Filing.

UE 307 / CUB
July 19, 2016
PacifiCorp Data Request 4

PacifiCorp Data Request 4

Refer to CUB/100, McGovern/10, line 22. Please provide supporting calculations for the intra-regional benefits of approximately $28 million.

CUB provides the attached spreadsheet, which demonstrates that if benefits don't increase at all over 2016 benefits--and if 2016 benefits only take into account 1/3 of the benefits from NV energy joining—then the benefits will be $26 million more than PAC has forecast. However, the attached spreadsheet shows that, under other assumptions, this benefit could be as high as $66 million.

In DR 45, CUB asks the Company to account for the difference between the Company's estimates of benefits (which are lower) and CAISO's report of benefits. The Company states that CAISO includes 3 EIM related benefits, and the Company includes 2 EIM related benefits in its calculation, the differing category being intra-regional benefits.

CUB then calculated several forecasts (low, medium, and high) of benefits, based on CAISO's reports of actual benefits to PAC. In Q4 2015, when NV Energy joined, PAC experienced benefits 30% higher than the same quarter, the year prior. However, in that Q4 2015, NV Energy was only in for the month of December, meaning that the 30% increase reflected less than a full quarter of experience with NV Energy. For the low estimate, CUB calculated 2016 benefits to be only 30% higher than 2015, and assumed no increase in benefits for 2017.

More realistically, CUB took data from the first full quarter that NV Energy had entered and compared it to the same quarter the year prior (Q1 2016 vs Q1 2015) and found that Q1 2016 showed PAC-only EIM benefits were 184% higher than the year prior. For the medium estimate, CUB assumed this increase for the rest of 2016 (over 2015) and assumed no additional growth for 2017. This resulted in approximately $60 million in benefits for 2017.

Finally, for the high estimate, CUB considered the growth observed in 2016 when NV Energy joined, and escalated additionally in 2017 for the likely entrance of PGE and Idaho Power. This resulted in approximately $66 million in benefits for 2017.Since, in DR 45, PAC identifies the difference between its own estimates and CAISO estimates as the intra-regional benefits, CUB identified the difference between its own forecasts based on CAISO's actual and the Company's forecasts as such.

CUB recognizes that there are imperfections in the data, such as PAC's partial quarter experience in 2014 and NV Energy's partial quarter experience in 2015.

However, CUB also recognizes that CAISO's reporting has been improved to better capture flexibility reserve benefits, 5 minute dispatch benefits and that CAISO's expects benefits to increase because of "improvements to market operations, expanding of the market with more participants, and expanding of renewable and transmission within the EIM footprint"[1]. Regardless of little experience and imperfect data, EIM benefits for 2017 need to be forecasted, and CAISO provides a sound, reasonable, and impartial basis for that forecast.

CUB also notes that by the time of the Company's final update, CAISO will have published additional EIM benefits reports and that those 2016 actuals will help inform 2017 forecasted benefits.

[1] 2014 Q report page 9 of 9

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PacifiCorp Data Request 5

PacifiCorp Data Request 5

Refer to CUB 100, McGovern/13. CUB claims that intra-regional benefits have not already flowed through GRID to customers through GRID optimization logic. If the GRID-optimized Net Power Costs (NPC) do not include intra-regional benefits achieved by participation in the EIM, please identify which costs or components of the optimized NPC could be reduced in order to achieve such benefits.

Response to PacifiCorp Data Request 5

When CUB asked the Company to reconcile the CAISO report and the Company estimates, the Company states that "the EIM does not create additional intra-regional dispatch benefits relative to grid"[2]. To that extent, CUB attests that the Company has yet to demonstrate that intra-regional benefits are being calculated and passed through to customers.

If the intra-regional benefits of EIM automation has generated benefits are not generated natively in GRID, they must be calculated, added, and flowed to customers. The Company is not doing this.

If the intra-regional benefits of EIM automation has generated benefits that are incorporated natively into GRID results, those intra-regional benefits are being withdrawn from the customers and returned to the Company in the form DA-RT, because DA-RT is calculated, in part, using pre-EIM data.

In either case, customers are not receiving the full intra-regional benefits from EIM investments.

[2] PAC response to CUB DR 45 - CUB's corrected Exhibit 107

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PacifiCorp Data Request 6

PacifiCorp Data Request 6

Refer to CUB/100, McGovern/14. Regarding the calculation of EIM benefits, CUB states "the calculation seems to be dependent on another number, which is the Export MWh/[MidC to COB transmission]."

a. Please confirm that the referenced calculation is contained in column L of tab 'ORTAM16 EIM Inter-reg AugUpdate' in CUB's Confidential Exhibit 108.

b. Please confirm that the referenced calculation does not impact the calculation of Export Margin ($/MWh Trans Avail) shown in column N of tab 'ORTAM16 EIM Inter-reg AugUpdate' in CUB's Confidential Exhibit 108.

Response to PacifiCorp Data Request 6

CUB confirms that ratio is contained in exhibit 108, column L, calculated by dividing column C by column K, Column K being the relevant column to the benefit discount.

The denominator (column K) in column L is also the denominator in column N, therefore, both columns are being scaled by the inverse of column K

In particular, the export benefit forecast uses column K (via column N) by diluting the dollars received per transfer because instead of calculating export benefit dollars as [$/MWh exported], column R, rows 21-63 calculate export benefit using [$/MWh of transmission made available]

Therefore K, the relevant column is used to determine the forecast of export benefits in the test year, in rows 21-63. CUB called the Company about this factor to specifically understand the importance. The Company responded saying that it was not used to calculate benefits for the existing year, but was used to calculate forecasted export benefits.

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PacifiCorp Data Request 7

PacifiCorp Data Request 7

Refer to CUB/100, McGovern/17. Referring to CUB's confidential exhibit 109, CUB states, "the Company seems to subtract the difference between COB and EIM prices as a lost opportunity cost."

a. Please provide specific reference within CUB exhibit 109 wherein COB market prices are contained.

Response to PacifiCorp Data Request 7

CUB finds this question confusing. Exhibit 109 is the Company's response to Staff's DR 42. The Company would have the best knowledge as to all the locations of COB market prices. However, in the Daily summary Column M, the Company incorporates lost opportunity. Moreover, in Hourly Summary Tab, column K, the Company lists "Lost opportunity Mid-C to COB". CUB in conversations with Staff and the Company attempted to decipher how the lost opportunity is being calculated and where it was utilized. CUB believes, after reviewing the Company's data response to Staff DR 42 on EIM benefits and costs, that lost opportunity costs are being incorporated into the Company's EIM benefit calculations. However, the Company's response to Staff DR 42 contains many incomplete references and broken cells that rely on workpapers not provided in the response.

Finally CUB notes that in testimony, CUB states that the Company seems to incorporate opportunity costs into the EIM cost approach, and that CUB believes the appropriate methodology would not include this. CUB seeks clarification on the Company's approach to this issue.

b. Does CUB agree that the 'Export Benefit excluding Lost Opportunity & Fees' calculated in CUB exhibit 109 is the sum of the fields Export $, Energy Cost, Variable O&M, and GHG cost (Columns C through F)? If so, please explain where CUB believes difference between COB and EIM prices is being subtracted out in the calculation of the EIM benefits?

Please refer to response 9a above.

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PacifiCorp Data Request 8

PacifiCorp Data Request 8

Please confirm the data request response provided as CUB's confidential exhibit 107 is the correct exhibit. Several references within CUB/100 are made to CUB/107 but CUB/107 does not contain the referenced information. See footnotes 26, 28, 32, and 40.

Response to PacifiCorp Data Request 8

CUB regrets the error. CUB/107 included an incorrect data response. CUB will be filing an Errata Filing with the OPUC to correct Exhibit 107.

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PacifiCorp Data Request 9

PacifiCorp Data Request 9

Refer to CUB/100, McGovern/22. CUB states "According to Exhibit 102 (footnote 46: UE 307 PAC/100/Dickman/107), the Company forecasts the entire fleet of QFs available and serving customers from January 1, which means that customers will pay the higher rates starting January 1, for resources that were not used and useful.

PacifiCorp Data Request 9a

a. Please provide specific reference to statements or data contained in PacifiCorp's Exhibits 102 or 107 supporting the statement that all QFs are included beginning January 1 regardless of the QF's commercial online date.

Response PacifiCorp Data Request 9a

CUB's statement was in reference to PAC/102/Dickman/3. While this spreadsheet shows some seasonal variation in QFs through the year, it does not show an increasing volume of QF's added over the course of the year. In fact, the total for January and February is greater than the total for November and December.

PacifiCorp Data Request 9b

b. Please refer to the attached Exhibit PAC/502 from the Company's Reply Testimony in UE 296, specifically rows 125 through 178. Does CUB agree that the QFs included in UE 296 (the 2016 TAM) were not all included beginning January 1?

Response to PacifiCorp Data Request 9b

PacifiCorp's Reply Testimony in UE 296 was subject to an additional update, which CUB understands included updates to contracts, including QFs. CUB did not review last year's updates to determine the 2016 QFs.

In order to understand historical QFs, CUB asked the Company DR 22. According to the answer to that data request, the Company forecast 1,006.43 MW of QF solar in the 2016 TAM, but has no additional installed capacity above the 80 MW that were available in 2015. (see attached DR 22-2)

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PacifiCorp Data Request 10

PacifiCorp Data Request 10

Refer to CUB/100, McGovern/22. CUB states 'not a single one of the projects forecast for 2016 [in UE 296] has come online.' Please provide documentation supporting this statement. Specifically identify the anticipated commercial operation dates for each solar QF project forecast for 2016 CUB claims has not come online. Identify which projects were anticipated to be online prior to the filing of its testimony on July 8, 2016?

Response to PacifiCorp Data Request 10

In CUB DR 22, CUB asks for both actual QF facilities and forecasts. In particular, for actual, CUB asks for "actual QF MW's for each period covered by the TAM. The Company, in part 22-2 provides this summary in response to actual, with no additional information:

Actual Solar Qualifying Facility (QF) Projects - Calendar Year 2014 through Calendar Year 2016					
Project Owner	**Project Name**	**Commercial Operation Date (COD)**	**Calendar Year 2014**	**Calendar Year 2015**	**Calendar Year 2016**
			2014 TAM (UE-264)	**2015 TAM (UE-287)**	**2016 TAM (UE-296)**
eBay	eBay Solar	1/30/2014	0.52	0.52	0.52
SunEdison	South Milford Solar	4/1/2015	Not Applicable	2.93	2.93
SunEdison	Laho Solar	7/14/2015	Not Applicable	3.00	3.00
SunEdison	Milford Flat Solar	7/23/2015	Not Applicable	3.00	3.00
SunEdison	Granite Peak Solar	8/21/2015	Not Applicable	3.00	3.00
SunEdison	Beryl Solar	8/24/2015	Not Applicable	3.00	3.00
SunEdison	Fiddler's Canyon 1	9/22/2015	Not Applicable	3.00	3.00
SunEdison	Fiddler's Canyon 2	9/22/2015	Not Applicable	3.00	3.00
SunEdison	Greenville Solar	10/29/2015	Not Applicable	2.19	2.19
SunEdison	Cedar Valley Solar	12/7/2015	Not Applicable	3.00	3.00
SunEdison	Fiddler's Canyon 3	12/21/2015	Not Applicable	3.00	3.00
SunEdison	Milford 2 SOlar	12/21/2015	Not Applicable	2.97	2.97
SunEdison	Buckhorn Solar	12/23/2015	Not Applicable	3.00	3.00
Juwi Solar	Pavant Solar	12/30/2015	Not Applicable	50.00	50.00
Scatec Solar	Utah Red Hills Renewable Park	Project has not been deemed commercially operational yet. Generating test energy	Not Applicable	80.00	80.00
Forecast			0.52	96.71	1,006.43
* There were no solar QF projects online prior to 2014.					

According to this spreadsheet, the 2016 TAM forecast 1,006.43 MW of capacity, but since the actual amount (the sum of the highlighted cells) was the same as 2015, CUB believes this demonstrates that no additional capacity has come on line in 2016.

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PacifiCorp Data Request 11

PacifiCorp Data Request 11

Refer to CUB/100, McGovern/28. Does CUB agree that the actual day ahead and real time transactions forming the basis of the Company's DA-RT adjustment are transactions that are executed prior to a given hour to balance the Company's system prior to entering that hour of operation? If not, please explain why not.

Response to PacifiCorp Data Request 11

First, CUB notes that a simple Google search shows that the definition of real-time balancing includes transactions that are executed within an hour. Second, CUB notes that the methodology for this adjustment changed from last year's TAM to this year's TAM, so CUB views the methodology of this adjustment as a moving target.

On page 30 of CUB's testimony, CUB describes this adjustment as relating to hourly purchases and reprints the Company diagram from Dickman (100/21) which shows monthly, daily and hourly purchases and sales.

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PacifiCorp Data Request 12

PacifiCorp Data Request 12

Refer to CUB/100, McGovern/28. Please explain how the Company's participation in the sub-hourly EIM market 'may begin to shrink' the occurrence of the Company balancing its position using standard products in the forward markets and reselling or repurchasing more granular portions also in forward or real-time hourly markets.

Response to PacifiCorp Data Request 12

It is CUB's understanding that the Company needs to continually balance its position. Additionally, pre-EIM, the Company had fewer options. Now, the Company has the option of transacting in the EIM market, volume that may have been moving in one of the other markets, may now be occurring in the EIM market. In order to participate in the EIM market, the Company must make transmission available, which reduces the potential volume of sales/purchases in the hour ahead market. Because the DA-RT adjustment is based on actual volumes, participation in the EIM could reduce the volume of sales/purchases that are included in the DA-RT adjustment. This would explain why the Company changed the DA-RT methodology to include additional pre-EIM months.

CUB Exhibit 206 is confidential and was submitted to each party designated to receive confidential information pursuant to Order 16-231.

CUB Exhibit 207 is confidential and was submitted to each party designated to receive confidential information pursuant to Order 16-231.

CUB Exhibit 208 is confidential and was submitted to each party designated to receive confidential information pursuant to Order 16-231.

CAISO benefits report	2014 Q4	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1	2016 Q2	12 mo total
PACE	2.31	2.63	3.26	4.51				
PACW	2.42	1.19	4.46	4.01				
PAC Total	4.73	3.82	7.72	8.52	6.17	10.85	10.51	36.05

	2015 Q4	2016 Q1	2016 Q2
PAC Total	6.17	10.85	10.51
year on year increase	30%	184%	36%

CAISO 2015 Q2 report pg 5 of 9
CAISO 2015 Q3 report pg 4 of 8
CAISO 2015 Q4 report pg 4 of 8 also the first quarter that NV Energy is reported
CAISO 2016 Q1 report pg 4 of 8

if 2017 is no change over 30% increase from 2015 Q4:

	2016 Q1	2016 Q2	Q3	Q4		PAC estimate	PAC reply est	difference	reply diff	
multiple		1.3	1.3	1.3						
	10.85	10.51	11.076	8.021	40.457	13.9	23.7	26.557	16.757	low

but NV energy was only in the EIM for one of the three months (december) in Q4 2015, so assume increase is in line with first full quarter that NV Energy joins

if 2016 increase is in line with increase from 2015Q1 to 2016 Q1 and there are no additional benefits in 2017

	Q1	Q2	Q3	Q4						
multiple			2.10	2.10						
	10.85	10.51	17.8993	12.96228	52.22158	13.9	23.7	38.32158272	28.52158	medium

if 2017 experiences a 30% growth over 2016 when NV energy joined because PGE/Idaho power may join

	Q1	Q2	Q3	Q4						
multiple	1	1	1	1.3						
	10.85	10.51	17.8993	16.85097	56.11027	13.9	23.7	42.21026819	32.41027	high

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CUB Data Request 70

CUB Data Request 70

In opening testimony (UE 307/Staff/100/Crider/14-15), Staff describes the net benefit calculation of EIM. In particular, Staff describes the cost portion.

In conversation with the Company, CUB asked about net benefit calculations and understood that the Company took the following approach: The Company, for the 2017 TAM, receives a monthly report from CAISO regarding transfers, including volume, timing, and origin/destination. The Company then goes back and finds which plant was dispatched, and uses that generation cost to calculate the cost portion. The Company also stated that this was in contrast to how it was done last year, which was to use an average of plant costs. CUB reads Staff's testimony to say that the Company uses the Bid Price to calculate export costs.

Please provide a formula for EIM net benefits, explicitly detailing: (1) import avoided cost calculation (2) import cost calculation (3) export revenue calculation and (4) export cost calculation.

Response to CUB Data Request 70

Energy imbalance market (EIM) Benefits = Import avoided cost + Export margin

Import avoided cost = Import cost – Avoided cost to generate

Import cost = (15-Minute Market (FMM) transfer price * FMM volume) + (Real Time Dispatch (RTD) transfer price * (RTD volume – FMM volume))

FMM transfer price = (PacifiCorp FMM LMP + Adjacent BAA FMM LMP)/2

RTD transfer price = (PacifiCorp RTD LMP + Adjacent BAA RTD LMP)/2

Avoided cost to generate = RTD import volume * PacifiCorp cost to generate (dollars per megawatt-hour ($/MWh))

Export margin = Export revenue – Export cost to generate

Export revenue = (FMM * FMM volume) + (RTD transfer price * (RTD volume – FMM volume))

Export cost to generate = RTD export volume * PacifiCorp cost to generate ($/MWh)

PacifiCorp cost to generate = starting point in the daily resource stack equal to RTD LMP in PACE and FMM LMP in PACW, which determines the marginal unit for the interval. Once the marginal unit is identified, the cost to generate is determined by

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moving up the resource stack, multiplying each generator's cost (i.e. bid) by available capacity until the total transfer quantity is reached.

Actual Solar Qualifying Facility (QF) Projects - Calendar Year 2014 through Calendar Year 2016

Project Owner	Project Name	Commercial Operation Date (COD)	Calendar Year 2014	Calendar Year 2015	Calendar Year 2016
			2014 TAM (UE-264)	2015 TAM (UE-287)	2016 TAM (UE-296)
eBay	eBay Solar	1/30/2014	0.52	0.52	0.52
SunEdison	South Milford Solar	4/1/2015	Not Applicable	2.93	2.93
SunEdison	Laho Solar	7/14/2015	Not Applicable	3.00	3.00
SunEdison	Milford Flat Solar	7/23/2015	Not Applicable	3.00	3.00
SunEdison	Granite Peak Solar	8/21/2015	Not Applicable	3.00	3.00
SunEdison	Beryl Solar	8/24/2015	Not Applicable	3.00	3.00
SunEdison	Fiddler's Canyon 1	9/22/2015	Not Applicable	3.00	3.00
SunEdison	Fiddler's Canyon 2	9/22/2015	Not Applicable	3.00	3.00
SunEdison	Greenville Solar	10/29/2015	Not Applicable	2.19	2.19
SunEdison	Cedar Valley Solar	12/7/2015	Not Applicable	3.00	3.00
SunEdison	Fiddler's Canyon 3	12/21/2015	Not Applicable	3.00	3.00
SunEdison	Milford 2 SOlar	12/21/2015	Not Applicable	2.97	2.97
SunEdison	Buckhorn Solar	12/23/2015	Not Applicable	3.00	3.00
Juwi Solar	Pavant Solar	12/30/2015	Not Applicable	50.00	50.00
Scatec Solar	Utah Red Hills Renewable Park	Project has not been deemed commercially operational yet. Generating test energy	Not Applicable	80.00	80.00
Forecast			0.52	96.71	1,006.43

* There were no solar QF projects online prior to 2014.