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August 2, 2017

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PACIFICORP's 2018 Transition Adjustment Mechanism
Docket No. UE 323

Dear Filing Center:

Please find enclosed the redacted version of the Rebuttal and Cross-Answering Testimony and Exhibits of Bradley G. Mullins on behalf of the Industrial Customers of Northwest Utilities ("ICNU") in the above-referenced docket.

The confidential portions of ICNU's testimony are being handled pursuant to Order No. 16-128 and will follow to the Commission via Federal Express.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

<u>/s/ Jesse O. Gorsuch</u>
Jesse O. Gorsuch

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the confidential portions of the **Rebuttal and Cross-Answering Testimony of the Industrial Customers of Northwest Utilities** upon the parties shown below by mailing a copy via First Class U.S. Mail, postage prepaid.

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

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 323

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In the Matter of	)
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PACIFICORP, dba PACIFIC POWER,	)
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2018 Transition Adjustment Mechanism.	)
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REBUTTAL AND CROSS-ANSWERING TESTIMONY

OF BRADLEY G. MULLINS

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

(REDACTED VERSION)

August 2, 2017

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204. I previously provided Opening Testimony in this matter—the 2018 Transition Adjustment Mechanism ("TAM") filing of Pacific Power (the "Company")—on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL AND CROSS-ANSWERING TESTIMONY?

A. I respond to the Rebuttal Testimony of Mr. Wilding filed on behalf of the Company, regarding the Company's proposed net power costs ("NPC") forecast for 2018 developed using the Generation and Regulation Initiative Decision Tools ("GRID") model. Specifically, I discuss Mr. Wilding's objection to evaluating longer-term transactions within the framework of the Day-ahead / Real-time ("DA/RT") system balancing adjustment. I also discuss reasons why a backcast would be a useful tool for the Commission, and parties, to evaluate the various "exogenous" adjustments that have been implemented within the GRID model framework over the years.

Finally, I also briefly express support for the Opening Testimony of Mr. Higgins on behalf of Calpine Solutions and his recommendation to transfer Renewable Energy Certificates ("RECs") to direct access customers over the period in which transition payments are calculated.

Q. WHAT LEVEL OF NPC HAS THE COMPANY PROPOSED IN ITS UPDATE?

A. The Company proposes to update the level of NPC reflected in rates to be $1,504.2 million on a total-Company basis, and $380.4 million on an Oregon-allocated basis.[1/] This amount represents a reduction from the Company's initial filing of approximately $10.2 million on an Oregon-allocated basis, including correction of the error in the DA/RT adjustment calculation identified in my Opening Testimony.

II. DA/RT ANALYSIS

Q. WHAT ANALYSIS DID YOU PREPARE IN OPENING TESTIMONY WITH RESPECT TO THE DA/RT ADJUSTMENT?

A. In Opening Testimony, I noted that the DA/RT adjustment excludes certain transactions executed more than seven days prior to the delivery date (">7 Day Transactions"). These transactions do have an impact on the overall dollars per megawatt-hour rates at which the Company makes sales and purchases, but are excluded from the Company's DA/RT analysis, ostensibly for the reasons described in the Company's Rebuttal Testimony. My analysis showed that when viewed through the framework of the DA/RT adjustment, these >7 Day Transactions resulted in approximately $21.8 million of average annual benefits in the periods subsequent to the start of the Energy Imbalance Market ("EIM").[2/] Accordingly, I recommended incorporating into the DA/RT adjustment the impact of the >7 Day Transactions, and calculating the adjustment over the period 2015 through 2016, corresponding to the period of EIM participation.

1/ PAC/100 at 3:7-8.

2/ This value can be calculated from Confidential Table 1R, below, by averaging the impact of >7 Day Transactions over the period 2015 and 2016.

Q. DID THE COMPANY ACKNOWLEDGE THAT THE >7 DAY TRANSACTIONS HAVE HISTORICALLY PRODUCED BENEFITS?

A. Yes. The Company acknowledged that the >7 Day Transactions have resulted in significant benefits relative to monthly market prices, particularly in the EIM period.[3/] The Company also correctly identified an error in my workpaper related to market prices in the period subsequent to June 2016. After making the correction, there is agreement that the impact of >7 Day Transactions is a \$6.8 million Oregon-allocated reduction to NPC, as detailed in Confidential Table 1R, below. In addition, in Exhibit ICNU/201 attached to this filing, I have updated the calculations formerly presented in Exhibit ICNU/104 to reflect the correction.

CONFIDENTIAL TABLE 1R

Corrected Impact of >7 Day Transactions on DA/RT Adjustment
Cost/(Benefit) over monthly market prices, \$millions

	<7 Day Trans.			>7 Day Trans.			All Balancing Trans.		
	Buy	Sell	Σ	Buy	Sell	Σ	Buy	Sell	Σ
2011 2012 2013 2014 2015 2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Annual:									
2011-2016	17.2	7.7	24.9	13.5	(18.9)	(5.3)	30.7	(11.2)	19.5
7/2011 - 6/2016	18.9	8.8	**27.7** (a)	16.9	(18.3)	(1.4)	35.8	(9.6)	26.3
2015-2016	18.9	4.4	23.3	9.3	(31.2)	(21.8)	28.2	(26.8)	**1.4** (b)

Adjustment:

(a) Company proposed:	27.7
(b) ICNU proposed:	1.4
(a) - (b) Total-Company impact	26.2
System Generation ("SG") factor	25.7%
Oregon-allocated impact	6.8
Remove Or. impact of "known" Short Term Firm	(0.4)
Adjustment:	6.3

3/ PAC/400 at 24:4-8 (including Confidential Figure 4).

Q. HOW DID THE COMPANY RESPOND TO YOUR ANALYSIS?

A. The Company disagrees that the >7 Day Transactions are appropriately considered, *at all*, when evaluating the forecast costs associated with system balancing. The Company offers no consistent explanation as to why the >7 Day Transactions have resulted in such benefits when analyzed in the DA/RT framework, although it does acknowledge the historical benefits. It makes statements, such as "[t]he fact that the forecasted short-term purchase price was greater than the actual short-term purchase price has no bearing on the rationale for the DA/RT adjustment,"[4/] which seemingly confute the very justification for using the DA/RT adjustment in the first place.

Q. DO YOU AGREE WITH THE COMPANY'S CONCLUSIONS?

A. No. The >7 Day Transactions either represent an additional benefit relative to the GRID model, or they do not. And, if they are in fact a benefit, they are appropriately included in the forecast as an offset to the DA/RT adjustment. It may be true that there are other factors, such as hedging considerations, that caused the >7 Day Transactions to produce benefits relative to monthly market prices in the historical period. That, however, does not mean that the offsetting benefits of the >7 Day Transactions should be excluded from the forecast.

Q. DO YOU BELIEVE IT IS INAPPROPRIATE FOR YOU TO RAISE THIS ISSUE, AS THE COMPANY SUGGESTS?

A. No. The Company implies that, since the Commission has historically not accepted my adjustments with respect to the DA/RT analysis, my analysis in this matter should be rejected *out of hand*.[5/] I take exception to the implication that it is inappropriate to raise the issue

[4/] Id. at 25:9-11.
[5/] Id. at 22:3-7.

related to >7 Day Transactions in this docket. Prior to this proceeding, I had not conducted any analysis considering the >7 Day Transactions within the DA/RT framework, although I certainly have been thinking a lot over the past two years about how the various components of the Company's system balancing interact.

The goal of my analysis in this proceeding was to take a fresh look at the DA/RT modeling adjustments from an objective point-of-view, in order to better understand and evaluate the adjustment. Suggestions that parties should be discouraged from presenting new analyses, or even further developing old ones, with respect to a modeling adjustment is somewhat concerning to me, even where the adjustment has been accepted by the Commission in the past.

Q. WHY DID YOU DECIDE TO INVESTIGATE THE ISSUE RELATED TO >7 DAY TRANSACTIONS IN OPENING TESTIMONY?

A. As has been discussed, the DA/RT adjustment is, at its roots, a historical comparison between the dollars per megawatt-hour rates for power transactions and average monthly market prices for a given market hub over a given period of time. Dr. Kaufman's Opening Testimony on behalf of Staff offers a good explanation of the mechanics of the adjustment.[6/]

My review in this matter was based on the question of whether there might be other factors influencing the overall dollars per megawatt-hour rates for system balancing sales and purchases used in the DA/RT adjustment, factors which were not considered in the Company's narrow formulation of the DA/RT adjustment. Staff shares these concerns,[7/] which parties

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[6/] Staff/200 at 13:1-15:4.
[7/] Id. at 15:1-4.

have discussed, but did not resolve, in the various workshop processes that have led up to this proceeding.

Q. WHY ARE THESE OFFSETTING FACTORS A CONCERN?

A. Under the Company's construct, if a day-ahead or real-time sale was made at a rate less than the monthly average price, it is included in the DA/RT adjustment as an additional cost, additive to the dispatch costs calculated in the GRID model, irrespective of any other factor influencing the transaction. If purchase is made at a rate greater than the monthly average price, it is also considered an additional cost.

The actual economics associated with any one of these transactions are, however, embedded as a component of the economic dispatch of the Company's entire system. The cost of such a transaction in actual operations, relative to GRID model dispatch, is therefore more complicated than a simple comparison to monthly market prices. A transaction made in any given period is driven by complex system interactions, which are not considered in the Company's analysis that uses monthly market prices as the benchmark of what constitutes an additional cost or benefit relative to GRID.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE COMPLEX SYSTEM INTERACTIONS THAT ARE NOT CONSIDERED IN THE DA/RT ADJUSTMENT?

A. As an example, consider a day with low market prices relative to the monthly average. To the extent that the Company made a large volume of sales on that particular day, it would result in additional cost in the DA/RT adjustment. It is not necessarily true, however, that those particular transactions represented an additional cost on the system. In fact, those low-priced sales transactions might have produced a great deal of economic benefits to the system, depending on other economic variables that impacted the Company's system dispatch on that day. If gas prices were similarly low on that particular day, the additional transactions may have been the result of increased gas plant dispatch, producing a great deal of incremental revenues, relative to the cost of fuel necessary to generate the transactions. That is, the "spark-spreads" driving those transactions may have resulted in a scenario where the transactions were beneficial to system, rather than being an additional cost.

In my Opening Testimony, the specific factor that I sought to better understand had to do with the subset of transactions that were executed more than 7 days prior to the settlement period. Similar to the concerns expressed by Dr. Kaufman,[8/] I questioned whether these longer-term transactions were producing benefits that offset the impact of the DA/RT adjustment.

Q. DOES THE GRID MODEL ALREADY INCLUDE THE IMPACT OF KNOWN SHORT-TERM FIRM TRANSACTIONS?

A. Yes. The Company makes a valid point that there are a small of amount of "known" short-term firm transactions, which are already included in the GRID model at fixed prices.[9/] These known transactions, however, represent only a small amount of the volumes considered in the >7 Day Transactions analyzed in my Opening Testimony. The Company's claim that *all* of the >7 Day Transactions are accounted for as known short-term firm is an interesting contention, since accounting for unknown volumes is a core part of the DA/RT adjustment. The Company described this in the 2016 TAM as follows:

> The Company added to its NPC forecast the incremental balancing volumes associated with using standard products to cover the open position determined by GRID. These volumes are priced so the overall cost of the Company's day-ahead

8/ Id. at 16:13-18:13.

9/ PAC/400 at 22:15-23:4.

> and real-time balancing transactions relative to the forecasted monthly market prices is equal to the historical average.[10]

In any case, Confidential Exhibit ICNU/202 provides a table showing that only a very small volume of known short-term firm transactions have been executed for the test period. As can be noted, (and as the Company acknowledges in its Rebuttal Testimony) in most months of the test period, the Company has not yet executed any known short-term firm transactions.[11]

Confidential Exhibit ICNU/202 also demonstrates that the benefit of the known transactions is also small relative to historical averages, comprising only a $1.7 million total-Company benefit in the July update, or $0.4 million, Oregon-allocated. That compares to average annual, total-Company benefits of $21.8 million during the EIM period in actual operations. The difference in actual versus modeled benefit of known short-term firm amounts might be (as the Company implies) a hedging benefit, or a premium, embedded in forward price curves.[12] The Company, however, did not present any empirical analysis to support its theory, nor have I undertaken extensive study of the matter, other than measuring the historical benefits of the >7 Day Transactions. In the past, however, I have observed significant forward premiums in gas prices,[13] so it would not surprise me if the historical benefits are a sort of hedging benefit, driven by risk premiums embedded in forward prices. Although that does not mean the benefit should be excluded.

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[10] In re PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism, Docket No. UE 296, Direct Testimony of Brian S. Dickman, PAC/100 at 29:22-30:3.

[11] PAC/400 at 22:19-20.

[12] Id. at 23:15-17.

[13] See In the Matter of Portland General Electric Company, 2017 Annual Power Cost Update Tariff, Docket No. UE 308, Redacted Opening Gas Hedging Testimony of Bradley G. Mullins, ICNU/200 at 7:3-9:24.

Q. ARE THE KNOWN SHORT-TERM FIRM TRANSACTIONS APPROPRIATELY CONSIDERED IN YOUR ADJUSTMENT?

A. Yes. To account for known transactions, I'd propose to apply the $0.4 million Oregon-allocated benefit of known short-term firm transactions that are already included in the GRID model as an offset to historical values calculated in my adjustment. This adjustment can be seen in Confidential Table 1R, above.

Q. ARE THE BENEFITS OF >7 DAY TRANSACTIONS APPROPRIATELY EXCLUDED BECAUSE THEY POSSESS HEDGING COMPONENTS?

A. Whether the offsetting benefits relate to the hedging components, or some other factor, is an irrelevant consideration. If there is an offsetting systematic benefit associated with these longer-term contracts, those benefits are appropriately applied against the impact of the DA/RT, irrespective of what is causing the benefit. In addition, it is important to consider that the transactions in question are not financial transactions, such as swaps or options, but are physical transactions resulting in the delivery of actual power.

Q. DO YOU AGREE THAT THE COMPANY HAS NOT MADE ANY CHANGES TO THE WAY IT OPERATES ITS SYSTEM AS A RESULT OF THE EIM?

A. One might consider the Company imprudent if it truly had not made any changes in the way that it balances its system following its joining the EIM. Thus, I find it somewhat perplexing that the Company would argue that the EIM has had *zero* impact on the way it transacts in term, day-ahead and real-time markets.[14/] While it is true that the Company still must produce balanced schedules in each hour, the Company now has the ability to bid capacity to be dispatched into the EIM, rather than sell that capacity into the hour-ahead market. This is one

[14/] PAC/400 at 27:4-29:2.

of many options now available to the Company, which were not reflected in the system balancing costs prior to the EIM.

In addition, the cost of the Company's system balancing transactions—detailed on Confidential Table1R—is positive evidence that the EIM has changed the way in which the Company balances its system. Between 2014 and 2015, the total cost of the Company's system balancing, relative to monthly market prices and including all transactions, declined by approximately [redacted]%, from $[redacted] million to $[redacted] million. The Company offered no valid explanation of why such significant reductions to the Company's system balancing costs, relative to monthly average prices, occurred in the period following its entrance to the EIM. Given the evidence that the Company has changed the way it balances its system following the EIM, I continue to believe it is appropriate to calculate the DA/RT adjustment over the period 2015 through 2016, corresponding to the Company's participation in the EIM.

Notwithstanding, even if the adjustment was not calculated over that period, including the >7 Day Transactions still results in a benefit in the DA/RT adjustment. For example, if calculated over the period 2011 through 2016, including all system balancing transactions, the DA/RT adjustment produces a value of $19.5 million, which is less than the $27.7 million amount the Company included in its initial filing.

Q. DID YOU RECOMMEND THAT THE COMMISSION REJECT THE DA/RT ADJUSTMENT ON THE BASIS THAT THE FORECAST IS UNRELIABLE?

A. While the Company seemed to suggest so, I did not recommend that the adjustment be rejected on the basis that it is unreliable. My intention was to note that the forecast of the DA/RT adjustment had the potential to be unreliable, which the Commission would appropriately consider when evaluating the adjustment. Since the impact of system balancing viewed within the DA/RT framework varies greatly year to year, I think it is appropriate to be less dogmatic about the approach used for this particular component of net power costs, and focus more on determining whether the totality of power costs is being established in a reasonable manner—a task the Company has been reluctant to perform through a backcast, as will be discussed below.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENT RELATED TO THE DA/RT ADJUSTMENT.

A. I continue to believe that it is appropriate for the >7 Day Transactions to inform the DA/RT adjustment. I also continue to believe that the DA/RT adjustment is best calculated to correspond to the period of EIM participation. After the correction noted above, as well as accepting the Company's position with respect to known short-term firm transactions, my adjustment results in an approximate $6.5 million Oregon-allocated reduction to NPC in this matter.

III. NEED FOR A BACKCAST

Q. WAS THE PURPOSE OF THE BACKCAST TO MODIFY THE GRID MODEL LOGIC, AS THE COMPANY SUGGESTS?

A. No. I'd characterize the Company's response with respect to a backcast as being somewhat misleading in this respect. The point of a backcast, from my perspective, is not meant to be a tool through which to propose changes to the core GRID model logic. The point also is not to "internalize [out-of-model] adjustments through modifications to the GRID model."[15/] Rather, the study would be used to validate the totality of power costs and figure out whether the model, including all of the "exogenous" modeling adjustments implemented over the years,

[15/] Id. at 45:15-18.

produces reasonable results. If not, the adjustments might be reconsidered or it might be determined that other changes are appropriately made to the modeling framework. Absent such an analysis, it is difficult to be assured that all of the offsetting impacts associated with the Company's various modeling adjustments get considered, and that certain costs and benefits are not being double-counted. I understand such an analysis can be difficult to perform, but it would provide better insight into the need for the DA/RT adjustment, as well as other adjustments to the Company's model. For that reason, especially considering the similar recommendation from Staff,[16/] I believe that the Commission is justified in requiring the Company to perform a backcast in its next TAM filing.

Q. COULD A BACKCAST SERVE OTHER IMPORTANT AND BENEFICIAL PURPOSES OUTSIDE OF THE TAM?

A. Yes. A study considering the accuracy of the model logic could inform many other aspects of the Company's regulated operations, including issues related to interjurisdictional allocation. The GRID model is often used in considering various interjurisdictional allocation approaches and there has often been a question as to whether the GRID model reasonably replicates the Company's actual operations. Having greater confidence in the model would be very useful when making allocation decisions that are based upon the Company's modeling forecasts.

Q. WHY DID THE COMPANY OBJECT TO PERFORMING A BACKCAST?

A. As a threshold matter, the Company did not dispute that it has performed backcasts in the past, around the time that the GRID model was first developed.[17/] ICNU was amongst the parties that reviewed those studies, which the Company used to justify the GRID model when first

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16/ See Staff/200 at 8:4-10:5.

17/ See ICNU/100 at 4:5-15; see also Re Pacific Power Light Request for a General Rate Increase in the Company's Oregon Annual Revenues, Docket No. UE 170, Surrebuttal Testimony of Randall J. Falkenberg, ICNU/111 at 24:13-24.

introduced. Those studies were performed a long time ago, and since then, many changes have occurred with respect to the model. Thus, when the Company suggests that a backcast is an unreasonable requirement that will produce no useful information, I question why it was reasonable to perform a backcast, and why such an analysis produced useful information, back when the GRID model was originally developed.

Q. IS IT UNREASONABLE TO PERFORM A BACKCAST BECAUSE GRID BALANCES THE SYSTEM DIFFERENTLY THAN IN ACTUAL OPERATIONS?

A. The Company believes that a backcast is an unreasonable requirement because GRID balances the system differently than actual operations. That, however, is the very reason why parties want the Company to perform a backcast in the first place. From my perspective, the goal of, and reason for doing, a backcast is to isolate the differences between the way in which GRID simulates system balancing, compared to way it is done in actual operations, with the ultimate objective of determining the cost of the impacts if there are differences and reconciling those differences within the modeling environment.

Q. IS THE ISSUE OF "PERFECT FORESIGHT" A PROBLEM FOR A BACKCAST?

A. The GRID model is certainly based on a static set of inputs. Whether that is appropriately characterized as "perfect foresight," I do not know. I do know, however, that the use of static inputs, relative to dynamic conditions experienced in actual operations, is a factor that one would isolate and analyze in a backcast, if performed the proper way. Accordingly, I do not view this to be an issue weighing against performing a backcast.

Q. DOES THE USE OF NORMALIZATION ASSUMPTIONS MAKE A BACKCAST IRRELEVANT?

A. No. A backcast would not use normalized assumptions. It would be based on the actual values experienced in the test period, such as actual loads, actual outages, actual prices, etc. To the extent the model populated with these non-normal results produces results different than experienced in actual operations, the differences could be isolated and understood. Exogenous adjustments and shaping methodologies should also be included in the backcast, which will serve to validate the need for those adjustments and methodologies. For example, the DA/RT adjustment would be considered based on the DA/RT values calculated for the historical year for which the backcast is performed, rather than using a four-year average.

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON THE NEED FOR A BACKCAST.

A. The Company's insistence on not performing a backcast is somewhat strange to me. As I see it, the Company is either objecting to the additional transparency that a backcast would provide, or wishes to avoid the time commitment necessary to perform one. In either case, I continue to believe the Company should work with parties to develop a backcast that provides meaningful information and which could be used to holistically consider the reasonableness of the Company's modeling methodologies.

IV. VALUE OF FREED-UP RECS

Q. DO YOU SUPPORT MR. HIGGINS' PROPOSAL ON BEHALF OF CALPINE SOLUTIONS?

A. Yes. I believe there is general agreement in this matter that departing direct access customers produce a benefit with respect to the electric utility's renewable portfolio standards ("RPS") compliance obligations, which is not presently considered in the calculation of transition adjustments. The departure creates what parties generally refer to as "Freed-up RECs," or RECs which the departing customer is paying for as a component of its transition adjustment payments, but which the utility may use to fulfill the compliance obligations of remaining customers. There does not appear to be much controversy with respect to the notion that

Freed-up RECs are created as a result of the departure of direct access customers and that the value of those Freed-up RECs is appropriately returned to departing customers.

The controversy that remains, however, surrounds the amount of value that should be returned, as well as the mechanisms for returning the value to direct access customers.

In my view, the most straightforward path around this controversy is to simply transfer the Freed-up RECs to the departing customer, either through a direct transfer or by allowing the utility to retire RECs on behalf of the departing customer's energy service supplier. This sort of approach avoids any question as to valuation, and for that reason is preferable. The mechanical aspects of this approach would, by necessity, carry some degree of complexity, although I have not seen any credible evidence that the complexity would impose an undue burden on the utilities or parties. For that reason, I recommend that the Commission begin to develop rules that will allow for such a REC transfer.

Q. DO YOU AGREE WITH THE COMPANY'S NOTION OF A FUTURE REC VALUE?

A. In the alternative, where a monetary adjustment is made to account for the value of Freed-Up RECs, the Company argues that a future REC value ought to be used, since the Company does not have an RPS compliance need until the late 2020s. While I agree with this notion, I do not agree with the way that the Company proposes to calculate the future value. In my view, the current market value for RECs is the best indication available of future REC values. Thus, I believe that the future value would be best established by using current market prices, calculated simply based on the average rate for sales transactions the Company has executed to date in 2017, and adjusted for the time value of money to the future period. This is in contrast to the Company's use of REC pricing obtained in the 2016 request for proposal, which is now outdated and stale.

Q. DOES THIS CONCLUDE YOUR REBUTTAL AND CROSS-ANSWERING TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 323

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2018 Transition Adjustment Mechanism.	)
	)

EXHIBIT NO. ICNU/201

HISTORICAL DART ADJUSTMENT CALCULATIONS - CORRECTED

(REDACTED)

Exhibit ICNU/201 contains Protected Information subject to Order No. 16-128 and has been redacted in its entirety.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 323

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2018 Transition Adjustment Mechanism.	)
	)

EXHIBIT NO. ICNU/202

IMPACT OF KNOWN SHORT-TERM FIRM TRANSACTIONS IN GRID

(REDACTED)

PacifiCorp 2018 Transition Adjustment Mechanism Filing
Impact of Known Short Term Firm Transactions in GRID.
Whole Dollars
Confidential

[redacted]

PacifiCorp 2018 Transition Adjustment Mechanism Filing
Impact of Known Short Term Firm Transactions in GRID.
Whole Dollars
Confidential

[redacted]

Total Benefit /Cost	**485,393**	**454,406**	**775,718**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1,715,518**
System Energy	25.7%	25.7%	25.7%	25.7%	25.7%	25.7%	25.7%	25.7%	25.7%	25.7%	25.7%	25.7%	25.7%
Oregon-Allocated	**124,943**	**116,966**	**199,674**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**441,583**

PacifiCorp 2018 Transition Adjustment Mechanism Filing
Calculation of Known Short Term Firm Benefit Relative to Monthly Market
Confidential

[redacted]

PacifiCorp 2018 Transition Adjustment Mechanism Filing
Calculation of Known Short Term Firm Benefit Relative to Monthly Market
Confidential

[redacted]

PacifiCorp 2018 Transition Adjustment Mechanism Filing
Calculation of Known Short Term Firm Benefit Relative to Monthly Market
Confidential

[redacted]

PacifiCorp 2018 Transition Adjustment Mechanism Filing
Calculation of Known Short Term Firm Benefit Relative to Monthly Market
Confidential

[redacted]

PacifiCorp 2018 Transition Adjustment Mechanism Filing
Calculation of Known Short Term Firm Benefit Relative to Monthly Market
Confidential

[redacted]

PacifiCorp 2018 Transition Adjustment Mechanism Filing
Calculation of Known Short Term Firm Benefit Relative to Monthly Market
Confidential

[redacted]

PacifiCorp 2018 Transition Adjustment Mechanism Filing
Calculation of Known Short Term Firm Benefit Relative to Monthly Market
Confidential

[redacted]