BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of Rocky Mountain Power's Application to Decrease the Deferred EBA Rate through the Energy Balancing Account Mechanism	**Docket No. 16-035-01 Direct Testimony of Philip Hayet For the Office of Consumer Services**

NONCONFIDENTIAL – REDACTED VERSION

Confidential Material Shaded in Gray

August 18, 2016

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Philip Hayet. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

Q. PLEASE STATE YOUR OCCUPATION, EMPLOYMENT, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am a utility regulatory consultant and Vice President of J. Kennedy and Associates, Inc. (Kennedy and Associates). I am appearing on behalf of the Office of Consumer Services ("Office").

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY KENNEDY AND ASSOCIATES?

A. Kennedy and Associates provides consulting services related to electric utility system planning, energy cost recovery, revenue requirements, regulatory policy, and other regulatory matters.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in OCS Exhibit 2D-1. I have participated in numerous PacifiCorp and Rocky Mountain Power (or the "Company") cases including PacifiCorp's 2014 General Rate Case ("GRC") (Docket No. 13-035-184), and the last two EBA proceedings covering calendar years 2013 (Docket No. 14-035-31) and 2014 (Docket No. 15-035-03).

I. <u>INTRODUCTION AND SUMMARY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Kennedy and Associates was retained by the Office to assist in reviewing Rocky Mountain Power's ("RMP" or "Company") 2016 Energy Balancing Account ("2016 EBA") Application pursuant to tariff Schedule 94. RMP, which is a subsidiary or business unit of

PacifiCorp, filed a deferred net power cost ("NPC") application on March 15, 2016, referred to as the 2016 EBA filing. RMP seeks approval from the Public Service Commission of Utah ("Commission") to adjust electric rates and true-up the collection of revenues for net power costs covering the 2015 calendar year. In its Application, the Company requested approval to recover $18.9 million in deferred EBA costs for the 2015 calendar year period. My testimony proposes $3,060,583 in changes to RMP's EBA request, and recommends that RMP's deferred NPC recovery be reduced by $1,326,464 on a Utah basis. In addition, I raise a concern that relates to the EBA process about the impact of the CAISO Energy Imbalance Market (CAISO "EIM") on the Company's net power costs. This is a particularly timely issue as the Company is currently investigating becoming fully integrated as a participating transmission owner in the CAISO.

Q. WHAT WAS THE BASE NPC PROJECTION AND ACTUAL NPC COST FOR CALENDAR YEAR 2015?

A. The base NPC projection built into rates, referred to as Base Energy Balancing Account Costs ("Base EBAC"), originated from the 2014 General Rate Case ("2014 GRC"). The 2014 GRC used a 12-month projected test year period covering July 2014 through June 2015. The 2014 GRC set the Base NPC rate to change in two steps based on a schedule. For calendar year 2015, the Step 1 rate was in effect for the first 8 months of the year, and the Step 2 rate covered the remaining 4 months of the year. The System Net Power Costs, as projected in the 2014 GRC was $1.494 billion, and was determined as:

8 / 12 times $1.495 billion + 4 / 12 times $1.491 billion

When allocated to Utah, this became $629.3 million. This number was then adjusted by subtracting the projected Utah wheeling revenue of $41.1 million, and the resulting Utah Base EBAC was $588.2 million.

The actual adjusted System net power cost for 2015 was determined to be $1.537 billion. When allocated to Utah, this became $668.0 million. This number was then adjusted by subtracting actual allocated Utah wheeling revenue of $40.9 million, and the resulting Utah Actual EBAC was $627.1 million.

Q. DID THE ACTUAL SALES VARY FROM THE PROJECTED SALES?

A. Yes, the actual sales were higher than projected sales by 883.3 GWh.

Q. WHAT WAS THE UNDER-RECOVERED BALANCE THAT HAD TO BE TRUED-UP?

A. The projected Utah Base EBAC amount of $588.2 million was used to establish a $/MWH rate for 2015 at which customers were charged for net power costs. However, since actual sales were higher than the projected sales, the actual revenue collected was $610.9 million. Thus, the under-recovered balance was computed as the difference between the Utah actual revenue collected, $610.9 million, and the Utah actual cost incurred, $627.1 million. Therefore, the 2015 under-recovered amount was $16.2 million ($627.1 – $610.9).

Q. WHAT WERE THE REMAINING STEPS TO DERIVE THE 2015 EBA RECOVERY AMOUNT OF $18.9?

A. First, the $16.2 million under-recovered balance was reduced to $11.3 million after applying the 70/30 percent sharing band ($16.2 * .7). Second, the EBA deferral balance was further reduced after accounting for 100% of the coal fuel savings at the Hunter and Huntington plants related to the closure of the Deer Creek mine, which reduced the EBA deferral balance by $2.8 million. Note that this adjustment was not subjected to the 70/30 percent sharing band. Third, carrying costs were computed and added to the EBA deferral balance. Interest was accrued based on a 6.0% annual interest rate as follows:

Interest through December 31, 2015	$0.4 million
Interest through October 31, 2016	<u>$0.9 million</u>
	$1.3 million

Fourth, per the stipulation in Docket No. 14-035-147 ("Deer Creek Settlement"), the EBA deferral balance includes 100 percent of the Utah-allocated amortization expense associated with the closure of the Deer Creek mine, which increases the under-recovered balance by $9.1 million.[1]

The final EBA deferral balance after accounting for interest and the Deer Creek mine impacts is $18.9 million ($11.3 - $2.8 + $1.3 + 9.1).

Q. PLEASE SUMMARIZE THE ADJUSTMENTS THAT YOU RECOMMEND.

A. First, I propose two adjustments related to avoidable forced outages that resulted in the inclusion of unnecessary replacement power costs in actual net power costs. The outages occurred at the Company's Lake Side and Craig power plants, and the total of both adjustments reduces the Utah allocated NPC deferral by **[BEGIN CONFIDENTIAL]** $........... **[END CONFIDENTIAL]** I also support an adjustment the Division identified to disallow Company true-ups or corrections of actual net power costs that occurred prior to 2015 that were included in calendar year 2015 net power costs. This adjustment reduces the Utah allocated deferral balance by **[BEGIN CONFIDENTIAL] $**................. **[END CONFIDENTIAL]**

Mr. Dan Martinez will discuss another adjustment that the Office recommends related to the Deer Creek Mine Closure Settlement and the calculation of interest, amounting to an adjustment of $465,312. A summary of OCS's proposed adjustments is provided in Table 1.

[1] The treatment of the Deer Creek mine closure was addressed in a stipulation approved by the Commission in Docket No. 14-035-147.

Table 1

[BEGIN CONFIDENTIAL]

Adjustment	System ($)	Utah Allocated ($) (after sharing)
Lakeside Outage Replacement Power (OCS Exhibit 2D-2)	…………	…………
Craig Outage Replacement Power (OCS Exhibit 2D-3)	………	……….
Out of Period Adjustments (DPU) (OCS Exhibit 2D-5)	………..	……….
Deer Creek Mine Amortization Interest (DPU)	465,312	465,312
Total Proposed	3,060,584	1,326,464

[END CONFIDENTIAL]

Together, these adjustments reduce the Company's deferral request by $1.3 million, which changes the EBA deferral amount from $18.9 million to $17.6 million.

Q. ARE THERE ANY OTHER EBA OR NET POWER COST RELATED ISSUES THAT YOU DISCUSS IN YOUR TESTIMONY?

A. Yes, the Company began to fully participate in financial obligations associated with the CAISO EIM in November 2014, and 2015 was the first full year of operation. Since 2015 was the first full year of operation, I believe this EBA review provides the ideal opportunity to evaluate how the EIM has affected ratepayers' net power costs in 2015, and compare the actual benefits of the EIM to the projection that was made at the time that PacifiCorp considered joining the EIM. As I discuss in more detail below, I recommend the Company be required to perform a study to validate the results of the CAISO EIM benefits analysis, and to compare those results to the original studies performed when PacifiCorp considered joining the CAISO EIM. The analysis should evaluate data assumption values that were used in the original study and compare those to actual values that occurred, compare methodologies to ensure that apples-to-apples approaches are used, and evaluate results to ensure that net benefits from joining the EIM have materialized.

II. GENERATING UNIT FORCED OUTAGE DISALLOWANCES

Q. PLEASE DISCUSS YOUR INVESTIGATION OF GENERATING UNIT FORCED OUTAGES THAT OCCURRED DURING THE EBA DEFERRAL PERIOD.

A. It is not unusual for generating units to fail and typically utilities incur higher operating costs when failures occur. However, ratepayers should not have to be responsible for bearing higher outage costs when failures are caused by operator errors, or by outages that are clearly avoidable.

In this proceeding, we reviewed forced outages that occurred during calendar year 2015 and determined there were two relatively long forced outages that should have been avoided. One outage occurred at Lake Side Unit 2 and the other at Craig Unit 1. The Lake Side 2 outage began in January 2015 and ended in March 2015. This outage was identified by both the DPU and the Office for further investigation. The Office has determined this outage was avoidable, and proposes an adjustment to compensate ratepayers for replacement power costs incurred**.** The Craig outage started in the EBA calendar year 2014 and ended in the EBA calendar year 2015, and both the Division and the Office recommended a disallowance for this outage in last year's EBA proceeding. Since the outage carried over into the 2016 EBA deferral period (calendar year 2015), both the Division and the Office are once again recommending a disallowance for this outage.

LAKE SIDE 2 CT 1 OUTAGE

Q. PLEASE DESCRIBE THE LAKE SIDE 2 CT 1 OUTAGE.

A. The Lake Side generating facility is a 1,203 MW Combined Cycle Gas Turbine ("CCGT") plant located about 35 miles south of Salt Lake City, Utah. Lake Side 2 is a fairly recent unit addition at the plant as Lake Side 2 began commercial operations in 2014 as a 2x1 combined cycle configuration, using two combustion turbine generators ("CT") and a single steam turbine generator.[2] Siemens Energy supplied the power island equipment and CH2M Hill Engineers, Inc ("CH2M Hill") was the Engineering, Procurement, and Construction ("EPC") contractor for the unit.

According to the 2015 Thermal Outage Summary, which was filed as part of the minimum filing requirements, **[BEGIN CONFIDENTIAL]** ………………………………… ………………………………………………………………………………………………… . ……………………[3] ……………………………………………………………………… ………………………………………………………………………………………………… ………………………………………………………………………………………………… ………………………………………………………………………………………………… ………...[4] ……………………………………………………………………………… ………………………………………………………………………………………………… ………………………………………………………[5] **[END CONFIDENTIAL]**

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[2]http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/EnergyGeneration_FactSheets/RMP_GFS_Lake_Side.pdf
[3] Attach EBA FR 6-6 CONF
[4] DR OCS 1.4, ……………………………………………………………….
[5] DR OCS 1.4, ………………………………………

Q. DID THE INVESTIGATION DETERMINE WHERE THE [BEGIN CONFIDENTIAL] ………………………………………..?

A. ……………………………………………………………………………………… ……………………………………………………………………………………… . ……………………………………………………………………………………… …………………………...[6] ……………………………………………………………… ……………………………………………………………………………………… ………………………………………………………………………………

Q. …………………………………………………………………………………... ………..?

A. ……………………………………………………………………………………... ……………………………………………………………………………………… ……………………………………………………………………………………… ……………………………………………………………………………………… ……………... ……………………………………...[7] ……………………………………… ……………………………………………………………………………………… ……………………………………………………………………………………… ………………. ………..[8]

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[6] DR OCS 1.4, ……………………………………………………………………………….., at page 21.
[7] Id at page 21. Note also that in referring to unit 22, Siemens meant Lake Side Unit 2, CT 2.
[8] Id at page 21.

Q. ……………………………………………………………………………….........……….. ………………………………………………………………………………………………… ……………………………?

A. ………………………………………………………………………………………………… ………………………………………………………………………………………………… .. ……………………………………………………………………………………………… ………………………………………………………………………………………………… ………………………………………………………………………………………………… . ………………………………………………………………………………………….

Q. ………………………………………………………………………………………………. ………………….….?

A. ………………………………………………………………………………………………. ……………………………………………………………………………………….... **[END CONFIDENTIAL]**

Q. DOES THE FACT THAT THE [BEGIN CONFIDENTIAL] ……………………………………………… [END CONFIDENTIAL] ABSOLVE PACIFICORP OF RESPONSIBILITY?

A. No it does not. First of all, it would be incorrect to say that PacifiCorp played absolutely no role in the construction of Lake Side 2 that was completed in 2014. Utilities such as PacifiCorp recover costs from customers for Owner’s Costs, which among other things includes a cost for Project Management. This means that PacifiCorp did play a role in the construction of the Lake Side unit, regardless of how minor the role may have been. Second, the fact that the **[BEGIN CONFIDENTIAL]** ……………………………….

[END CONFIDENTIAL] does not mean that the responsibility for the outage should shift to the shoulders of ratepayers. It is true that ratepayers should be responsible for paying prudently incurred costs associated with constructing units, however, they should not also have to take on responsibility for paying additional costs that might arise when **[BEGIN CONFIDENTIAL]** ……. **[END CONFIDENTIAL]** in the construction process occur. Certainly it was entirely appropriate that neither the ratepayer nor the Company had to pay the cost to repair the unit, but, the Company, not the ratepayer, was the party responsible for hiring the **[BEGIN CONFIDENTIAL]** …………………………………………….. ……………………… **[END CONFIDENTIAL]** and the Company not the ratepayer should be the party responsible for paying the increased net power costs that occurred when **[BEGIN CONFIDENTIAL]** ……………………………………………………………… …………………... **[END CONFIDENTIAL]**. Ratepayers should simply not be held responsible for the replacement power costs resulting from this outage, and the fact that the mistake was made by **[BEGIN CONFIDENTIAL]** ………………………….. **[END CONFIDENTIAL]** should not mean that PacifiCorp should be allowed to shift its own responsibility to the shoulders of the ratepayers for the replacement power costs caused by the extended outage.

Q. PLEASE DESCRIBE THE PROCESS YOU USED TO DEVELOP THE LAKE SIDE 2 CT 1 OUTAGE ADJUSTMENT.

A. From MFR 6-6, the Company reported that the outage period was **[BEGIN CONFIDENTIAL]** …………………………………………………………………. …………………………………………………………………………………………… …………………………………………………………………………………………… ……………………………………………………………………………………………

….. **END CONFIDENTIAL].** However, given that the Lake Side plant is a cycling gas plant whose dispatched capacity fluctuates widely on a daily basis relative to the cost of power available in the market, we developed an estimate of the amount of energy that the Lake Side unit would have produced had it not suffered the extended forced outage based on a simplified dispatch analysis.

Q. WHAT KIND OF MODEL DID YOU CREATE TO PERFORM THE SIMPLIFIED DISPATCH ANALYSIS?

A. We developed an hourly dispatch model in Excel that required inputs including the average cost of operating Lake Side 2, and the hourly cost of market energy. The average cost of operating the unit on a $/MWH basis was derived from the actual costs incurred and actual generation produced by Lake Side 2 during 2015. The hourly cost of market energy was downloaded from the CAISO website and represented the cost to purchase or sell energy in the CAISO EIM. The model included a ramp rate constraint, which we set to 100 MWs per hour based on a review of actual Lake Side CT operations data from 2015, and it included a forced outage rate assumption of 5%, which we believe is reasonable for a CCGT unit. The model determined when it would be economic to operate Lake Side 2 CT 1 by comparing the average cost of operating Lake Side 2 to the cost of market energy each hour. If the cost of market energy was less than the cost of operating the unit, Lake Side 2 CT 1 would dispatch. The model also had a test that would prevent the CT from turning on and off on an hourly basis, and typically the dispatch resulted in the unit being operated with a minimum up and a minimum downtime of about 6 hours.

Q. WHY DO YOU BELIEVE THIS ANALYSIS IS REASONABLE TO DERIVE THE OUTAGE REPLACEMENT COST FOR THE LAKE SIDE CT?

A. First, simplified analyses are quite often used in developing replacement power cost estimates. PacifiCorp, has in fact, relied on the use of a simplified approach to develop estimates of replacement power costs in past EBA analyses. The approach that we relied on for the dispatch of the Lake Side CT is a variation of an analysis that I am aware that other utilities including Southern Company and AEP have used.[9]

Q. IS THERE A MORE ACCURATE MODELING APPROACH THAT COULD BE USED TO DERIVE THE ESTIMATE OF REPLACEMENT POWER COSTS?

A. Yes, there is, but it requires considerably more effort, and PacifiCorp does not even use this approach when it develops replacement power cost estimates. The approach would require use of a production cost model, such as GRID. Two runs of GRID would have to be made covering the historic period when the Lake Side CT was on outage. The first run would include the CT on outage, and the second run would assume the outage had not occurred, and therefore, the CT was available for dispatch. The difference in the production cost results represents the replacement power cost associated with the Lake Side 2 CT 1 outage. The problem in using this approach is that it would require a benchmark to be performed, which is typically time consuming. The benchmark would be performed to ensure that the results of the GRID run with the Lake Side CT on outage reflects, as accurately as possible, the actual net power cost results that did occur. As I mentioned, I do not believe that this modeling approach is necessary, and I believe the approach that we developed is reasonable for determining the Lake Side CT outage replacement costs.

[9] Georgia Power Fuel Cost Recovery Proceeding, Docket 39638-U, Rebuttal Testimony David Poroch and Jeffrey Weathers, November 18, 2015, AEP Ohio Review of Capacity Charges, Case No. 10-2929-EL-UNC, Rebuttal Testimony Eugene Meehan, May 11, 2012.

Q. WHAT DID YOU ASSUME REGARDING THE STEAM TURBINE GENERATOR THAT WOULD HAVE BEEN ABLE TO RUN MORE IF LAKE SIDE 2 CT 1 WERE AVAILABLE?

A. In the analysis, we assumed that additional Lake Side capacity would have been available for dispatch beyond the Lake Side 2 CT 1 capacity, had CT 1 not suffered an outage. In reality, if CT 1 had been available, then additional capacity would have also been available from the steam turbine generator that relies on the heat output from the CT in order to operate. We estimated that 140 MW of additional steam turbine generator capacity would have been available had CT 1 not suffered the outage, and we derived the additional replacement power cost associated with that additional capacity.

Q. WHAT IS YOUR ESTIMATE OF THE REPLACEMENT POWER COST ASSOCIATED WITH THE LAKE SIDE 2 CT 1 OUTAGE?

A. Based on our analysis, we determined that the amount of energy that Lake Side 2 CT 1 and the steam turbine would have produced was 200,748 MWh, and the replacement cost value of that energy was **[BEGIN CONFIDENTIAL]** $............. **[END CONFIDENTIAL]** We then computed the impact on the Utah deferral balance after accounting for the 70% sharing mechanism. The proposed adjustment is presented in OCS Exhibit 2D-2, which indicates that the Utah EBA deferral is reduced by **[BEGIN CONFIDENTIAL]** $........... **[END CONFIDENTIAL]**

CRAIG UNIT 1 OUTAGE

Q. PLEASE DESCRIBE THE CRAIG OUTAGE.

A. I discussed this outage thoroughly in my 2015 EBA Direct Testimony (filed August 18, 2015), therefore, I will only provide a summary in this testimony. I include an excerpt from my prior testimony regarding the Craig outage as OCS Exhibit 2D-4. The Craig Station is located near Craig, Colorado, and is a 1,304 MW coal plant that PacifiCorp jointly owns with Tri-State Generation and Transmission ("Tri-State") and other utilities (PacifiCorp owns 19.3% of Units 1 and 2). The 427 MW Craig 1 unit was forced out of service on **[BEGIN CONFIDENTIAL]** ……………………………………………. ………………..[10] **[END CONFIDENTIAL]** During the 2015 calendar year, PacifiCorp experienced a possible loss of **[BEGIN CONFIDENTIAL]** …………………………… ………………………………………………………………………………………… . ……………………………………………………………………………………… ………………………………………………………………………………………… . ……………………………………………………………………………………….. ………………………………………………………………………………………… ……………………………………………….. **[END CONFIDENTIAL]**

Q. DO YOU BELIEVE THE COMPANY SHOULD BE PERMITTED TO RECOVER REPLACEMENT POWER COSTS ASSOCIATED WITH THIS OUTAGE?

A. No, I do not. As I discussed in my prior testimony, the Craig 1 outage could have been avoided if **[BEGIN CONFIDENTIAL]** ……………………………………………… ………………… **[END CONFIDENTIAL]**. Therefore, I continue to believe that it would be improper to require ratepayers to pay for replacement power costs associated with this outage.

[10] OCS 2.4(c)

Q. PLEASE DESCRIBE THE ADJUSTMENT YOU RECOMMEND CONCERNING THE CRAIG UNIT 1 OUTAGE.

A. Using the same methodology described for the Lakeside outage, I compared Craig's average operating cost to the CAISO market cost, for each hour during the 6-day outage period. Since Craig is an economic baseload unit, the model confirmed that it would probably have run significantly through the period had it been available, and it would have produced 10,402 MWh that would have served the System. Since Craig Unit 1 was not available, this economic generation was replaced by higher cost generation or market purchases. The replacement power cost associated with the Craig unit outage during 2015 is **[BEGIN CONFIDENTIAL]** $.............. **[END CONFIDENTIAL]** on a PacifiCorp System basis. The proposed adjustment as presented in OCS Exhibit 2D-3, indicates that the Utah EBA deferral is reduced by **[BEGIN CONFIDENTIAL]** $............ **[END CONFIDENTIAL]**

III. OUT OF PERIOD COSTS

Q. HAVE YOU REVIEWED THE OUT OF PERIOD COSTS IDENTIFIED BY THE DIVISION?

A. Yes. The Division has taken the position that corrections of actual net power costs that occurred at any time prior to the start of the deferral period (January 1, 2015), whether positive or negative, are impermissible and should not be accounted for in the EBA. I have reviewed the Division's adjustments and have considered its justification, and I agree that out of period costs and revenues should not be permitted to be included in the EBA deferral balance.

Q. WHAT IS THE NATURE OF THE COSTS THE DIVISION HAS IDENTIFIED THAT IT RECOMMENDS DISALLOWING?

A. The Division's adjustment to the EBA deferral balance on a total Company basis amounts to a total reduction of **[BEGIN CONFIDENTIAL]** $................. **[END CONFIDENTIAL]** In essence, these are adjustments to adjustments that the Company identified to its 2015 net power cost deferral balance. The Company first developed its estimate of the EBA deferral balance based on 2015 net power costs, and it then made adjustments to account for additional costs that it believed were legitimate to include in 2015 EBA costs. The Company described these costs in Annual Filing Requirement ("AFR") 15, which indicates that these adjustments relate to **[BEGIN CONFIDENTIAL]** ……………………………………………………………………………………….. ……………………………………………………………………………………………… **[END CONFIDENTIAL]** The Company also included a description of settlement amounts in AFR 6. The Division reviewed each of these categories of costs, and determined that adjustments were necessary to items 1, 2, and 6 to remove out of period impacts that occurred prior to January 1, 2015.

Q. WHAT WAS THE COMPANY'S COAL COST ADJUSTMENT AND WHAT IS THE DIVISIONS RECOMMENDED CHANGE TO THE COMPANY'S ADJUSTMENT?

A. The Company explained in AFR 15 that the **[BEGIN CONFIDENTIAL]** ……………. ……………………………………………………………………………………………… ………………………………………..… **[END CONFIDENTIAL]** related to periods prior to the inception of the EBA beginning October 1, 2011. The Company's **[BEGIN CONFIDENTIAL]** ………………………………………… **[END CONFIDENTIAL]**, and some of the costs (both positive and negative) embedded in that adjustment related to activities that occurred prior to the start of the deferral period. The Division removed the positive and negative costs that occurred prior to January 1, 2015. In the case of the Division's coal cost adjustment, the Division actually increased the 2015 EBA balance by **[BEGIN CONFIDENTIAL]** ………………… **[END CONFIDENTIAL]**.

Q. THE SECOND CATEGORY OF ADJUSTMENTS THAT THE COMPANY MADE AND THAT THE DIVISION REVIEWED WAS PRIOR PERIOD ADJUSTMENTS. DID THE DIVISION RECOMMEND A CHANGE TO THAT?

A. The Company explained in AFR 15 that in its Prior Period Adjustment, it removed **[BEGIN CONFIDENTIAL]** $................ **[END CONFIDENTIAL]** in costs that had been included initially in the EBA balance, but that had occurred prior to October 1, 2011, which was the initial start of the EBA. The Division agreed with that but found that there were other costs that should have been removed as well. Essentially, the Company drew a line at eliminating any costs that were incurred prior to October 1, 2011, and the Division drew a line at eliminating any costs that were incurred prior to January 1, 2015. The Division argued that once the Commission issued an order establishing rates in prior EBA cases, those rates were considered final and the Company cannot change those rates by adding in new costs later, which is essentially what the Company is doing in this EBA proceeding by making adjustments for costs that occurred prior to January 1, 2015.[11] The Division found that there were **[BEGIN CONFIDENTIAL]** $....................................... ……………………………………… **[END CONFIDENTIAL]** that related to events that

[11] Division's 2016 EBA Audit Report for Rocky Mountain Power, David Thomson Direct Testimony, Exhibit 1.2, at page 27.

occurred in 2014 and that were included in the 2015 EBA balance, and the Division recommends that those costs be removed. The Office agrees with the Division.

Q. WHAT WAS THE COMPANY'S [BEGIN CONFIDENTIAL] ……………………… …………………………… [END CONFIDENTIAL] AND WHAT IS THE DIVISION'S RECOMMENDED CHANGE TO THE COMPANY'S ADJUSTMENT?

A. The Division explained that the Company made a **[BEGIN CONFIDENTIAL]** $............. …………………………………………………………………………………………… …………………………………………………………………………………………… **[END CONFIDENTIAL]** Based on the Division's position that costs related to events that occurred in prior periods, in this case, 2014, should not be corrected in the 2015 EBA balance, the Division recommends removing this **[BEGIN CONFIDENTIAL]** $............ **[END CONFIDENTIAL]** amount from the EBA balance.

Q. DO YOU AGREE WITH THE DIVISION THAT OUT OF PERIOD COSTS SHOULD NOT BE INCLUDED IN THE 2015 EBA BALANCE?

A. Yes I do. I agree with the Division that once the Commission finalizes rates from prior periods, it has established rates to be charged to customers and the Company should not be permitted to adjust those rates retroactively, which is in effect what it is doing by introducing costs from a finalized prior period into a future EBA period. In its order on the EBA Interim Rate Process issued August 30, 2012 (Docket Nos. 12-035-67, 09-035-15, 11-035-T10), the Commission established its preference that final rates should go into effect close in time to when the EBA calendar year ends, and that interim rates should not be part of the EBA process. In establishing this position, the Commission explained that it wanted to avoid having a process that would result in multiple rounds of litigation of the same issues, which could conceivably happen if a cost from a prior period was accounted for in a future period.[12] It is conceivable, that the Company could identify a change to the rate that was finalized in one EBA period, and then effectuate that change by introducing costs into multiple future EBA periods. In effect, the changes that the Company would make in each of the multiple future periods could be argued in each of the future EBA proceedings. The Commission found that multiple rounds of litigation of the same issues would be inefficient and unjustified. The Division makes another valid point that "hypothetically, if the EBA had sharing bands until 2025, then the true-up or adjusting of costs from October 1, 2011 to January 1, 2024 could be done in the 2025 deferral period."[13] I agree with the Division that the Company should not be permitted to do this, and I believe that the Commission has established a preference for bringing finality to the rate setting process. I believe the Company must respect the fact that once final rates are approved no further costs or revenues should be introduced in a later EBA calendar year period.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND FOR OUT OF PERIOD ADJUSTMENTS?

A. I concur with the Division that **[BEGIN CONFIDENTIAL]** $..............., **[END CONFIDENTIAL]** should be removed from the System EBA balance. This translates to a **[BEGIN CONFIDENTIAL]** $............ **[END CONFIDENTIAL]** adjustment on a Utah Basis, as is presented in OCS Exhibit 2D-5.

IV. CAISO EIM

Q. WHEN DID PACIFICORP BEGIN TO PARTICIPATE IN THE EIM?

[12] Commission's August 30, 2012 Order at page 12.

[13] Division's 2016 EBA Audit Report for Rocky Mountain Power, David Thomson Direct Testimony, Exhibit 1.2, at page 29.

A. PacifiCorp began participating in the CAISO EIM with financially binding transactions on November 1, 2014, and 2015 was the first full calendar year of participation. Since the Company has now completed a full year of participation, this EBA is an appropriate time for the Commission to review the impacts of the EIM.

Q. PLEASE BRIEFLY DESCRIBE THE EIM?

A. The EIM uses the CAISO's automated scheduling and dispatch systems to more optimally balance its participating members' loads and resources in real-time using a larger portfolio of resources spread across all of the members' regions. The balance of resources is performed using an automated 5-minute and 15-minute scheduling and dispatch process. The EIM automatically manages congestion using locational marginal prices. By the end of 2016, PacifiCorp, NV Energy, Puget Sound Energy, Arizona Public Service, and the existing CAISO are all expected to be participants in the EIM.

Q. PRIOR TO THE START OF THE EIM, WHAT STUDY WAS PERFORMED AND WHAT BENEFITS WERE IDENTIFIED ASSOCIATED WITH PACIFICORP'S PARTICIPATION IN THE EIM?

A. In March 2013, Energy and Environmental Economics, Inc. ("E3"), who was retained by the CAISO, produced a report that studied the benefits of PacifiCorp joining the CAISO EIM. E3 estimated the benefits for one year, 2017, using ABB's GridView production cost simulation model that represented the Western Region Interconnection. 2017 was selected as a representative year since it was a little over two years after the start of the EIM. E3 estimated savings from reduced inter-regional costs between PacifiCorp and the CAISO[14],

[14] Inter-regional benefits were derived considering the difference in GridView production cost results from cases with and without the EIM modeled.

reduced intra-regional costs within the PacifiCorp Balancing Authority Area[15], reduced flexible reserve requirements[16], and savings from a reduction in curtailed renewable energy[17].

E3's results, restated in 2015 dollars, indicated that PacifiCorp's benefit of joining the EIM would range from $11.0 to $56.9 million on an annual basis.[18] The range in benefits was dependent on the assumption E3 made of the transmission transfer capability that would exist between PacifiCorp and the CAISO, and the level of hydro generation assumed to be available that could be used to provide flexibility reserves.

Q. HOW WERE THE BENEFITS OF THE EIM EXPECTED TO AFFECT RATES THAT CUSTOMERS PAY?

A. The benefits of the EIM could have influenced the rate setting process in the last GRC when net power cost rates were set, however, since the GRC was so new at the time, the Company chose not to model the impacts of the EIM in its GRID projections. As a result, any benefits of the EIM would be reflected in actual EBA costs. Therefore, any benefits of the EBA not reflected in net power cost rates set during the GRC would be trued-up in the 2015 EBA proceeding.

Q. IF RATES WERE SET HIGHER THAN THEY OTHERWISE SHOULD HAVE BEEN, AND BENEFITS OF THE EIM WERE PROJECTED TO BE BETWEEN

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[15] Intra-regional benefits were derived by assuming that PacifiCorp's intra-regional savings would be proportional to the CAISO's intra-regional savings that had occurred in 2009.

[16] Flexible reserve benefits were derived using another GridView production cost modeling analysis focused on operating reserves, and considered the difference in production cost resulting from carrying different levels of operating reserves.

[17] Reduced curtailed renewable energy was determined by performing two GridView production cost runs that evaluated the difference in two levels of renewable resources, one with and one without a curtailment. The amount of curtailed energy was then multiplied by the value of renewable energy.

[18] PacifiCorp-ISO Energy Imbalance Market Benefits, E3 Report, March 13, 2013, Table 6, page 35. The 2012$ values were increased by 4.5% using a GDP deflator to state the values in 2015 dollars.

$11.0 AND $56.9 MILLION, WHY DID PACIFICORP STILL END UP WITH AN UNDER-RECOVERED BALANCE OF $18.9 MILLION FOR THE 2015 PERIOD?

A. The simple answer is that while benefits of the EIM did occur in actual operations that were not projected, the benefits were not large enough to exceed other unexpected costs that occurred in 2015 that were not accounted for at the time net power cost rates were set in the last GRC. Though Mr. Wilding did not explain why the EIM benefits were within the lower half of the range that E3 determined, he did discuss the variance in net power costs compared to the projection that was made during the GRC. He explained that net power costs were higher than expected due to the actual operations having less hydro and wind generation compared to the projection, and the actual operations having significantly less wholesale sales revenue, which was partially offset by the actual results having a reduction in purchase power, coal and gas expenses.[19] Therefore, despite the benefits of the EIM being included in the EBA period, the costs that were greater than projected still resulted in an under-recovered balance of $18 million in 2015.[20] Without the EIM, the under-recovered balance would have been even higher.

Q. DID THE COMPANY DISCUSS THE MAGNITUDE OF THE EIM BENEFIT IN 2015?

A. Mr. Wilding only explained that the CAISO published quarterly reports ("CAISO Reports") that estimated the benefits of the EIM in 2015.[21] However he did not provide any explanation for the magnitude of the benefits, nor did he compare the actual benefits to the projected benefits estimated in the E3 study to explain the variances in results.

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[19] Michael Wilding Direct Testimony, lines 141 to 232.

[20] Note that $9 million of this under-recovered balance was due to the inclusion of the amortization expense associated with the closure of the Deer Creek mine in the 2015 EBA balance per the Settlement Agreement in docket 14-035-147.

[21] Michael Wilding Direct Testimony, lines 239 through line 245.

Essentially, Mr. Wilding noted that the EIM benefits attributable to PacifiCorp were determined to be approximately $26.2 million on a total-company basis, which translates to about $11 million on a Utah basis for 2015. Based on my review of the E3 study, it appears that the CAISO benefits of the EIM on a total Company basis ($26.2 million) is within the lower half of the range of estimated benefits projected in the E3 study, which suggested the benefits could range from $11.0 to $56.9 million.

Q. HOW DID THE CAISO DEVELOP ITS ESTIMATE OF EIM BENEFITS FOR 2015?

A. The CAISO performed an analysis comparing actual costs with the EIM in operation to a counter-factual analysis that assumed the EIM did not exist. The CAISO did not perform a production cost dispatch, but instead analyzed actual CAISO balancing transactions that occurred and determined what costs PacifiCorp would have incurred instead to balance its system if the EIM did not exist.[22]

Q. DID YOU VERIFY THE CAISO DERIVED SAVINGS RESULTS?

A. No, it was not possible to do so. While the CAISO provides documentation regarding its methodology for determining EIM benefits, neither we nor PacifiCorp could review the analysis the CAISO performed. PacifiCorp explained the reason it could not obtain the CAISO's work papers in response to OCS 2.13.

> The Company is unable to verify the California Independent System Operator's (CAISO) calculation of EIM Benefits due to the fact that the CAISO utilizes an internal database of information, including confidential and third-party information, as well as analytical software algorithms that are not available to the Company.

[22] http://www.caiso.com/Documents/EIM_BenefitMethodology.pdf, Effective with Q1, 2016 EIM benefits report.

Q. WHY DO YOU BELIEVE THE COMMISSION SHOULD REQUIRE AN EVALUATION TO BE PERFORMED AT THIS TIME TO EVALUATE THE ACTUAL EIM BENEFITS IN THIS EBA PROCEEDING?

A. An evaluation of the EIM benefits in the EBA should be required at this time because 1) 2015 was the first full calendar year that PacifiCorp was a participant of the EIM, 2) pursuant to the 2014 GRC Stipulation, deferred O&M costs relating to the EIM, are to be considered in a future rate case, at which time, the prudence of such costs shall be determined.[23] Thus, an evaluation of the EIM benefits now would provide valuable information that parties could use in the next rate case, and 3) the Company is currently participating in a stakeholder process to become a full member of the CAISO market. PacifiCorp should be ordered to clearly calculate the actual benefits regarding the EIM in order to evaluate whether PacifiCorp's further plans to join the CAISO would result in additional net benefits, incremental to what has already been achieved in the EIM.

Q. DID THE COMPANY DEVELOP ANY OTHER ANALYSES OF THE EIM BENEFITS IN 2015 BESIDES THE CAISO ANALYSIS?

A. In addition to the CAISO analysis, the Company also provided an analysis that it conducted of a portion of the EIM impacts related to just inter-regional EIM benefits that occurred in 2015, in response to OCS 1.12. That analysis indicated that the total Company inter-regional EIM benefit was **[BEGIN CONFIDENTIAL]** $............................ **[END CONFIDENTIAL]** in 2015. While the order of magnitude of the Company's results was consistent with the CAISO results, these results only reflect one benefit of the EIM, inter-regional EIM benefits. The Company stated in OCS 1.12 that it "has not quantified the

[23] 2014 Rate Case, Commission Order Issued August 29, 2014. Paragraph 30 of the Settlement Agreement.

benefits associated with either reduced flexibility reserves or intra-regional EIM dispatch during 2015."

Q. HAS THE COMPANY CONDUCTED A SIDE-BY-SIDE COMPARISON OF ANY OF THE STUDIES IT IDENTIFIED?

A. No, the Company has not evaluated the differences in the methodologies, nor the differences in the results produced in any of the studies it identified. The Company stated in response to OCS 2.13, "The Company has not attempted to reconcile the modeling assumptions in the E3 study with its actual operations."

Q. DO YOU BELIEVE THIS WOULD PROVIDE USEFUL INFORMATION?

A. Yes, I believe that it would be helpful for parties to better understand the analyses that the Company has represented as containing the benefits of joining the CAISO EIM, particularly so that parties can be assured that the projected benefits are in fact materializing in actual operations. Since the E3 study was performed, none of the studies performed to evaluate actual EIM benefits seem to be comparable to the original E3 study. The following table is provided to draw out distinctions in some of the key assumptions, methodologies, and results of the analyses the Company identified. The table indicates the inconsistencies in the studies, including different benefits that were quantified, different methodologies that were studied, and different time periods evaluated.

Table 2

[BEGIN CONFIDENTIAL]

	E3 EIM March 2013 Study (Table 6)	**CAISO EIM Benefits Quarterly Report**	**PacifiCorp Response to OCS 1.12**
Benefits Quantified	Inter-regional dispatch, intra-regional dispatch, flexibility reserves, and renewable curtailment	More efficient dispatch, reduced renewable energy curtailment, reduced flexibility reserves	……………..
Methodology	GridView production cost modeling analyses	Counterfactual dispatch analysis without performing sophisticated unit commitment simulations	………………… …………………..
Representative Period	2017 (2012$)	2015	…….
Breakdown PacifiCorp ($M / year)	Inter-regional $7.0 – $8.9 Intra-regional $2.3 –$23.0 Flexibility $1.2 – 22.5 Renewable $0 – $0	Q1: $3.82 Q2: $7.72 Q3: $8.52 Q4: $6.17	………………. …………….. ……………
PacifiCorp Total ($M / year)	$10.5 – $54.4 2012$ or $11.0 – $56.9 2015$	$26.2	$........

[END CONFIDENTIAL]

Q. BESIDES EVALUATING NET POWER COST BENEFITS OF THE EIM, HAS THE COMPANY PERFORMED A NET BENEFITS CALCULATION BASED ON ACTUAL EIM RESULTS?

A. No. A net benefits calculation would compare the net power cost benefits of participating in the EIM to the costs that would be incurred to be a participant in the EIM. Neither the CAISO's study nor PacifiCorp's study performed a net benefit calculation that subtracted the actual capital and on-going operating expenses that PacifiCorp incurred to participate in the EIM in 2015 from actual 2015 EIM net power cost benefits.

Q. ARE YOU SUGGESTING THAT PARTICIPATING IN THE EIM IS NOT BENEFICIAL TO PACIFICORP'S RATEPAYERS?

A. No, I am not suggesting that I do not believe the EIM is beneficial to PacifiCorp's ratepayers. I think that it probably is. However, I am concerned that none of the results in any of the studies that have been presented to evaluate the EIM are transparent and verifiable, and as I have noted the studies are not consistent.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE COMPANY'S PRESENTATION OF EIM BENEFITS?

A. Yes. The Company has discussed the benefits of the EIM, and it points to analyses performed by parties outside of this proceeding that are not easily verifiable. Also, the Company has seemingly made little effort to perform any analysis to evaluate and interpret the results of the studies. I believe that this proceeding provides the ideal opportunity for the Company to comprehensively show that the major operational changes brought about by joining the EIM have in fact been in the customer's best interests.

Q. WHAT ADDITIONAL INFORMATION SHOULD THE COMPANY PROVIDE?

A. I recommend the Company be required to perform a study to validate the results of the CAISO EIM benefits analysis, and to compare those results to the original E3 study. The analysis should evaluate data assumption values that were used in the E3 study and compare those to actual values that occurred, compare methodologies to ensure that apples-to-apples approaches are used, and evaluate results to ensure that net benefits from joining the EIM have materialized.

Q. BESIDES HAVING THIS INFORMATION FOR THE EBA, WHY ELSE MIGHT THIS INFORMATION BE USEFUL?

A. In a press release issued April 14, 2015, PacifiCorp announced that it has made a commitment to explore the feasibility and benefits of joining the CAISO as a fully participating member.[24] E3 was selected once again to perform a benefits study that was published in October 2015[25], and a stakeholder input and review process has begun to evaluate PacifiCorp plans for joining. Subsequently, the Company will seek this Commission's approval to join the CAISO. The information that I recommend would be useful to parties as they participate in the stakeholder input and review process. I also believe that the evaluation of the EIM would be necessary information to have when analyzing projections of benefits to PacifiCorp of joining the CAISO as a full participating member. Absent a more comprehensive and quantifiable understanding of the net benefits of PacifiCorp's participation in the EIM, it is not clear how it would be possible for the Company to demonstrate that joining the CAISO provides incremental benefit to what has been achieved to date.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

[24] http://www.pacificorp.com/about/newsroom/2015nrl/study-joining-california-iso.html

[25] Based on our cursory review of the study E3 published in October 2015, the methodology used in this study is completely different than what it used to analyze PacifiCorp joining the EIM. Once again, this leads to questions about consistency in analyses used in studies related to participation in the CAISO.