Docket No. 18-035-01
Exhibit DPU 2.2 Dir
Daymark Energy Advisors EBA Audit Report for
Calendar Year 2017 – Public Executive Summary

ENERGY BALANCING ACCOUNT AUDIT FOR ROCKY MOUNTAIN POWER FOR CALENDAR YEAR 2017 (DOCKET NO. 18-035-01)

PUBLIC EXECUTIVE SUMMARY

PREPARED FOR

Division of Public Utilities
State of Utah

PREPARED BY

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I. EXECUTIVE SUMMARY

In its Corrected Report and Order in Docket No. 09-035-15 issued March 3, 2011 ("EBA Order"), the Public Service Commission of Utah ("Commission") approved the implementation of the Energy Balancing Account ("EBA") to recover the differences between Rocky Mountain Power's ("RMP"), a business unit of PacifiCorp ("PacifiCorp" or the "Company") actual EBA costs and approved forecasted ("Base") EBA costs established in the general rate case ("GRC") or cases establishing rates during the EBA deferral period. The Commission found in its Order that an EBA mechanism as modified by the Commission was in the public interest and would result in rates that were just and reasonable.

On March 15, 2018 RMP filed a request to recover $2.8 million for excess EBA-related cost incurred during 12-month Deferral Period from January 1, 2017 through December 31, 2017[1]. The RMP's request represents nine components, including five credits and four costs. The request is summarized in Table 1 of the direct testimony of Michael Wilding, which is reproduced in Figure III-1 below. The credits include $4.4 million in EBA deferral, $2.9 million for savings related to the Deer Creek Retiree Medical Obligation, $2.8 million related to settlement of the 2017 EBA, $0.1 million in accrued interest through April 2017, and $0.5 million related to adjustments arising from a non-generation agreement with a special contract customer. The cost components considered in the application include $4.0 million related to an adjustment for sales made to a special customer, $9.1 million in Deer Creek mine amortization expense, $0.3 million in costs related to the Utah Subscriber Solar program, and $0.1 million in costs related to an adjustment arising from a settlement agreement with a special contract customer. All components represent Utah-allocated amounts. For the first time, none of the $2.8 million deferred EBA cost is subject to a sharing band.

Daymark Energy Advisors ("Daymark") was retained by the Division of Public Utilities ("Division" or "DPU") to assist in reviewing RMP's application to increase the deferred EBA rate through the EBA mechanism in Docket No. 18-035-01. The scope of our assignment was to ascertain whether the actual costs included in the EBA filing were incurred pursuant to an in-place policy or plan, were prudent and were in the public interest. This report presents the results of and the conclusions from that review. This review was similar to reviews that we performed for the Company's application to approve rate changes to recover (or refund) deferred EBA costs incurred at the end of

[1] Docket No. 18-035-01, Application to Increase the Deferred EBA Rate Through the Energy Balancing Account Mechanism, Page 1.

2011 presented in Docket No. 12-035-67, calendar year 2012 presented in Docket No. 13-035-32, calendar year 2013 presented in Docket No. 14-035-31, calendar year 2014 presented in Docket No. 15-035-03, calendar year 2015 presented in Docket No. 16-035-01, and calendar year 2016 presented in Docket No. 17-035-01.

This executive summary does not contain any confidential information. The remainder of this report does contain significant amounts of confidential information provided by RMP, and it explains the basis for our conclusions. The full report can be provided to parties that have signed the appropriate non-disclosure agreements for receiving material deemed to be confidential by RMP.

The Division is conducting a parallel review and analysis of the EBA deferral filing. Division Staff will be issuing its own report summarizing the results of its review. This report summarizes only the results of Daymark's review and analysis. Thus, the result contained in this report should be considered as complementing the work done by Division Staff.

Actual vs. Base NPC

The NPC category with the largest variance between Base and Actual values is wholesale sales revenue ($183 million increase). Purchased power expense also added $4 million to base NPC, resulting in a $187 million variance for wholesale sales and power purchases. Daymark's assignment included reviewing the variance to understand the underlying drivers of the difference and to ensure that differences can be explained reasonably. We do not consider forecast "accuracy" to be a material issue in this review (particularly given the wide temporal mismatch between the 2014-15 test period and the 2017 deferral period), but rather focus on the drivers of difference that are within PacifiCorp's control.

The general decrease in wholesale sales for resale coupled with lower average sales prices resulted in increased Actual NPC. Higher purchases also drove an increase in Actual NPC over Base NPC, though the impact was almost entirely mitigated by lower purchase prices. The variance from Base NPC is generally explainable by market condition changes between the Base NPC forecast for the 2014-15 test period and actual conditions during the 2017 deferral period, as well as changes in long-term contracts in effect for the respective periods.

Outages

One task was to review and assess actual plant outages to ensure that these outages and their cost impact on the EBA charge is appropriate. We examined the information provided as part of the filing and conducted additional discovery.

Our review of forced, maintenance, and extended planned outages at PacifiCorp's thermal plants during the EBA deferral period yielded 29 outages that appeared to be avoidable and resulted in unnecessary increases to Company-wide NPC. Of these 29 outages that warranted additional scrutiny, seven outages demonstrated sufficient imprudence that we recommend reducing EBA costs to reflect replacement power costs related to the outages.

In the case of outages caused by avoidable mistakes or oversight by the Company or its third party vendors, we recommend the adjustment of EBA costs based on the incremental market power costs during the outage period relative to generation costs if the unit had been operating normally. Estimation of replacement power costs is necessarily imprecise because it is impossible to know with certainty the PacifiCorp dispatch, bilateral transactions and market outcomes in the counterfactual scenario with the subject unit online. Our methodology relies on available market data or proxy data, actual Company costs and reasonable assumptions to construct counterfactual scenarios.

OUTAGE	START MONTH	EST. LOST MWH	RECOMMENDED EBAC ADJUSTMENT (COMPANY-WIDE NPC)
Outage A	May	6,324	$21,384
Outage B	Apr	25,795	$265,673
Outage C	Sep	27,305	$705,475
Outage D	May	26,341	$80,391
Outage E	Jan	24,314	$132,375
Outage F	Oct	30,463	$21,505
Outage G	Mar	70,693	$728,023
TOTAL		**211,235**	**$1,954,826**

Figure I(ES)-1. Summary of outage-related EBA adjustment recommendations.

The table above summarizes our recommendation with respect to EBA adjustments on a Company-wide NPC basis. The Division's separate report and testimony calculates the impact of our recommended adjustments on RMP's requested EBA recovery amount. On a Utah-allocated basis these adjustments result in a reduction of $840,267 to RMP's requested recovery of deferred EBAC.

Natural Gas and Power Transactions

Daymark also evaluated a sample of trading transactions for accuracy, completeness and prudence. From a workload perspective, this task constituted the largest component of our audit. Between 2013 and 2017, PacifiCorp engaged in tens of thousands of transactions on a system-wide basis for natural gas and electricity that settled in the 2017 EBA deferral period. The costs or proceeds of these transactions flow through into net power costs. The transactions fall into three broad categories: hedging, system balancing and other. Transactions are also classified as either physical or financial depending on whether physical delivery is involved.

We developed a sample of 46 broadly-representative transactions (including 23 transactions related to the Company's hedging program) and accounting entry groupings and conducted extensive discovery on these transactions. The sample included 12 gas financial, 12 gas physical, and 22 power physical transactions. Sample transactions were targeted for selection based on characteristics identified in the trade capture data provided in response to Filing Requirement 6(b), either to facilitate investigation of specific issues or questions or to ensure a broadly representative sample. We built on knowledge gained from similar review in previous EBA cases, including two visits (in 2013 and December 2015) to PacifiCorp's trading headquarters in Portland, Oregon to meet trading staff and witness trading activity.

For the sample transactions, we submitted detailed data requests for initial data, as well as several targeted follow-up sets. The data requests sought information that would shed light on why the transactions were done, how the terms of each deal fit in with the Company's market view at the time and whether each deal conformed to risk management and corporate governance policies.

Based on our review of the sample transactions and the supporting information provided to us, we find no reason at this time to adjust energy balancing account or net power costs for sample transactions reviewed.

However, review of one transaction exposed a weakness in PacifiCorp's policies and practices regarding monitoring and reporting potential breaches in individual trader limits. Though traders are not financially incentivized to seek unauthorized trades beyond their limits, this is still an important corporate governance control that must be monitored. PacifiCorp has taken some positive steps to address this weakness since becoming aware of it recently. We support the practical steps taken and suggest that the Company formally adopt the control requirement in the Energy Risk Management policy.

Energy Imbalance Market Participation

We were asked to review the impact of PacifiCorp's third full calendar year of participation in the California Independent System Operator's ("CAISO") Energy Imbalance Market ("EIM"). PacifiCorp's participation in EIM impacts actual NPC in several ways, both directly and indirectly. First, there are direct costs and revenues associated with EIM transactions administered through the CAISO settlement system. As a result of trading energy imbalance through the EIM, the Company's own generation dispatch changes relative to what would have occurred absent the market, impacting fuel and purchased power cost indirectly. These impacts are not precisely quantifiable because they involve comparison to a counterfactual. Estimation of these impacts is necessary to determine if participation in EIM on balance reduces NPC.

RMP has offered testimony that, "participation in the EIM provides benefits to customers in the form of reduced Actual NPC"[2]. The two main sources relied upon for this conclusion are PacifiCorp's own analysis showing $25.7 million in inter-regional benefits in the deferral period and CAISO's published EIM Benefits Report estimating a wider subset of benefits attributable to PacifiCorp of $37.41 million. We reviewed the two studies to verify that customers benefit from the Company's participation in the EIM.

Based on our high-level review of public reports produced by CAISO supporting its benefits estimates we have found no reason to challenge CAISO's methodology or its findings that EIM participants benefit significantly from real time imbalance trading facilitated by the market. Daymark performed a more detailed review of PacifiCorp's benefits study, including "spot checks" of the underlying data and calculations for some periods. The methodology employed by PacifiCorp is a reasonable estimate of benefits associated with EIM participation. We find no evidence that it substantially overstates benefits of participation.

[2] Direct Testimony of Michael G. Wilding, Page 16, Line 315 – 316.