ENERGY BALANCING ACCOUNT AUDIT FOR ROCKY MOUNTAIN POWER FOR CALENDAR YEAR 2022 (DOCKET NO. 23-035-01)

PUBLIC EXECUTIVE SUMMARY

NOVEMBER 7, 2023

PREPARED FOR

Division of Public Utilities
State of Utah

PREPARED BY

Daymark Energy Advisors

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 May 1, 2023, RMP filed a request to recover approximately $175 million in deferred EBA costs incurred during the 12-month Deferral Period from January 1, 2022, through December 31, 2022.[1] RMP's request represents the net of three components, including one credit and two costs, as well as interest accrued through June 30, 2023. The request is summarized in Table 1 of the direct testimony of Jack Painter, which is reproduced in Figure III-1 below. The credit is $52.6 million for special contract customer adjustments. The cost components in the application are $220.8 million related to EBA costs and a $0.48 million adjustment for Utah situs resources. Interest accruals add $5 million to the total requested EBA recovery. Two new components included were a rollover of $2.0 million from the 2021 EBA collection true-up and a $0.6million credit of the 2022 EBA final order. All components represent Utah-allocated amounts, and there is no sharing band.

[1] Docket No. 23-035-01, Rocky Mountain Power, Application to Increase the Deferred EBA Rate Through the Energy Balancing Authority Account Mechanism, May 1, 2023.

Calendar Year 2022 EBA Deferral		Exhibit RMP___(JP-1) Reference
Actual EBA ($/MWh)	$ 27.40	Line 6
Base EBA ($/MWh)	18.81	Line 12
$/MWh Differential	$ **8.59**	
Utah Sales (MWh)	25,756,887	Line 5
EBA Deferrable*	$ 220,783,416	Line 14
Special Contract Customer Adjustment*	(52,608,601)	Line 17
Utah Situs Resource Adjustment*	476,032	Line 18
Total Deferrable	$ 168,650,846	Line 19
2021 EBA Collection True-Up	$ 1,970,714	Line 23
2022 EBA Final Order Adjustment	(597,795)	Line 24
Interest Accrued through December 31, 2022	1,708,678	Line 25
Interest Accrued January 1, 2023 through March 31, 2023	1,312,791	Line 27
Interest Accrued April 1, 2023 through June 30, 2023	1,984,581	Line 28
Requested EBA Recovery	**$ 175,029,815**	Line 29

** Calculated monthly*

Figure ES-1. Summary of Calendar Year 2022 EBA Deferral Calculation[2]

Daymark Energy Advisors ("Daymark") was retained by the Division to assist in reviewing RMP's application to increase the deferred EBA rate through the EBA mechanism in Docket No. 23-035-01. The Company is requesting approval to recover approximately $175 million in deferred EBA costs covering the differences between EBA costs incurred in the calendar year 2022 and Base EBA costs collected in rates during that same period. 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 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 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, calendar year 2016 presented in Docket No. 17-035-01, calendar year 2017 presented in Docket No. 18-035-01, calendar year 2018 presented in Docket No. 19-035-01, calendar year 2019 presented in Docket No. 20-035-01, calendar year 2020 presented in Docket No. 21-035-01 and calendar year 2021 presented in Docket No. 22-035-01.

[2] Docket No. 23-035-01, Direct Testimony of Jack Painter, Page 4, Table 1.

This Executive Summary does not contain any confidential information. The remainder of this report explains the basis for our conclusions and contains significant amounts of confidential information provided by RMP. The full report is available to parties that have signed the appropriate non-disclosure agreements for material RMP has deemed to be confidential.

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

Actual vs Base EBA Costs

EBA Costs ("EBAC") are composed of Utah-allocated NPC net of Utah-allocated wheeling revenues and production tax credits ("PTC"). Actual EBAC were higher than Base EBAC for the deferral period.[3] That difference was multiplied by Utah sales to obtain the EBA deferrable amount of $220.8 million, which is the driver of RMP's EBA deferral request. Daymark's assignment included reviewing this specific 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, but rather focus on the drivers of the difference that are within PacifiCorp's control. We reviewed the drivers of the difference between actual and Base for two of the EBAC components: NPC and PTC.

Increased purchased power expense ($337 million) and increased natural gas expense ($311 million), offset by the increased wholesale sales revenue ($62 million) comprise most of the approximately $583 million increase in actual NPC versus Base NPC. The increase in sales revenue and the increase in purchased power expense were driven primarily by higher spot market costs in 2022. Short-term volatility and the need for very high-priced market purchases to serve load during times of regional supply tightness account for this. The Company's purchases net of sales were greater than forecast because of higher load and lower-than expected wind, hydro and natural gas-fired generation. The variance from Base NPC is generally consistent with and explainable by market condition changes between the Base NPC forecast for the 2021 test period and actual conditions during the 2022 deferral period.

[3] Direct Testimony of Jack Painter, Page 4, Table 1.

PTC are included in the EBA calculation for the second year based on the Company's 2020 GRC filing in Docket 20-035-04. PTC are per kWh credits for generation from certain Company-owned wind facilities that offset federal income taxes, reducing EBAC.

Actual PTC were $4.7 million more than Base PTC, reducing EBAC. However, the Company's PTC-eligible wind facilities generated less energy (and corresponding PTCs) than expected in 2022, resulting in an increase in the EBA deferral request of approximately $10 million relative to what it would have been with wind facilities producing at long-term expected ("P50") levels. Annual variability is to be expected, and we find no reason to recommend a disallowance based on a single year under-performance of wind resources. However, over a longer period of time, under-performing years should be balanced by years with higher production and more positive actual PTC results.

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 in filing requirements and conducted additional discovery.

Daymark reviewed the thermal, wind, and hydro outage data as provided in the EBA filing and the supporting documentation as provided by RMP. Further documentation was sought for a select number of outages that were selected based on the narrative description provided. After reviewing the filing requirements and data request responses provided, we found no reason to adjust the EBA costs because of the hydro or wind outages. However, further review of the following specific thermal outages was performed.

Our review of forced, maintenance, and extended planned outages at PacifiCorp's thermal plants during the EBA deferral period yielded 13 outage events that warranted further investigation to determine whether there were any unnecessary increases to Company-wide NPC. Of these outages that warranted additional scrutiny, 3 outages affecting 4 units demonstrated sufficient imprudence that we recommend reducing EBA costs to reflect replacement power costs related to the outages.

In addition to recommendations regarding outage imprudence and replacement power cost disallowance, we also find that the Company's lack of emphasis on providing plant specific evidence of what the Plants are doing to minimize outage durations to be of concern. Further, it is incumbent on the Company to make every effort to make sure that "learnings" from outage events are properly vetted and corrective actions taken across the fleet documented to help proactively minimize future outages.

The table below summarizes our recommendations with respect to EBA adjustments totaling $1,694,816 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 outage related adjustments result in a reduction of$778,683, including interest to RMP's requested recovery of deferred EBAC.

Outage	Start Month	Est. Lost MWh	Recommended EBAC Adjustment*
Outage A	October	13,549	$552,947
Outage B	February	3,338	$123,306
Outage C	May	7,617	$491,785
Outage D	May	8,159	$526,778
Total		**32,662**	**$1,694,816**

** Company-Wide NPC*

Figure ES-2. Summary of outage related EBA adjustment recommendations

Natural Gas & Power Transactions

Between 2013 and 2022, PacifiCorp engaged in tens of thousands of transactions on a system-wide basis for natural gas and electricity that settled in the 2022 EBA deferral period. The costs or proceeds of these transactions flow 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 54 broadly representative transactions (including 37 transactions related to PacifiCorp's hedging program). 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 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 natural gas sample transactions and the supporting information provided to us, we find no reason at this time to adjust the energy balancing account or net power costs for the sample natural gas transactions reviewed.

Based on our review of the power physical transactions and the supporting information provided to us, we find no reason at this time to adjust EBA costs for all but five of the power physical deals included in our sample. Five of the sample deals were identified as “long buys,” hedging transactions that may increase risk because they extend already long positions. We identified an additional four transactions not in our sample that shared the same problematic patterns of purchasing a hedge to make a long position longer. Based on an extended review of the deals in the context of the Company’s new hedging policy implemented in July 2021, we find that these nine long buys have not been shown to be prudent. We recommend that the EBA deferral amount should be adjusted for the $13,903,376 losses associated with these transactions. 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 transaction-related adjustments result in a reduction of $6,485,693, including interest to RMP’s requested recovery of deferred EBAC.