Docket No. 23-035-01

DPU EXHIBIT 1.1 Dir – PUBLIC
EXECUTIVE SUMMARY

January 1, 2022 – December 31, 2022

2023 EBA AUDIT REPORT FOR ROCKY MOUNTAIN POWER

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EXECUTIVE SUMMARY – NON-CONFIDENTIAL

The Utah Division of Public Utilities (Division or DPU) and its outside consultant, Daymark Energy Advisors, Inc. (Daymark), have completed the 2023 audit of Rocky Mountain Power's (RMP, Company) Energy Balancing Account (EBA) for the calendar year 2022 (2022 Deferral, Deferral Period). The Division recommends a recovery amount of $167.8 million for the 2022 Deferral Period. This recommended recovery includes Daymark's $7.3 million recommended adjustments described below.

Summary observations with recommended adjustments:

1. The Company's level of documentation was generally comparable to that provided in prior filings.

2. The Company was generally complete and timely in its Data Request responses; however, the Company has not provided responses to the Division's Data Requests 14 and 18.[1] As needed during the audit, the Company's personnel were available and generally responsive to the Division's requests.

3. The Company reported a large Total PacifiCorp wide 2022 EBA deferral of $609.8 million in unallocated and unadjusted Net Power Costs above the base set in the 2020 general rate case.

   The $609.8 million Total unadjusted EBA deferrable (Actual NPC – Base NPC) was due to:

   $58.8 million decrease from sales for resale,
   $361 million increase from purchased power,
   $17.3 million increase from wheeling expense,

[1] Completeness and timeliness here refer to the data requests themselves, not to the question of whether the responses satisfy prudence standards.

($21.8 million) decrease from coal fuel expense,
$311.4 million increase from natural gas expense,
$.6 million increase in other (wind) expenses.

4. The Utah allocated portion of the Total 2022 EBA deferral totaled $276.9 million in unadjusted Net Power Costs above the base set in the 2020 general rate case.

5. After the Company's inclusion of the Utah allocated wheeling revenues, PTCs and collection variance adjustments, the combined impact on the Total Deferrable EBA equaled $220.8 million.

   The $276.9 million Utah allocated NPC deferrable (Actual NPC – Base NPC) was reduced to $220.8 million due to:

   ($33.7 million) in Wheeling Revenues Variance (Actual – Base),
   ($4.7 million) in PTC Variance,
   ($17.7 million) in Base NPC Collection Variance,

6. The $220.8 million Utah Allocated EBA deferrable was further adjusted to the Company's Requested EBA Recovery, as filed, to just over $175 million.[2] The $220.8 million is more than double the Company's largest previously requested net deferral recovery of $107.6 million for EBA deferral year 2021.[3]

   The Company's adjustments to the $220.8 million EBA deferrable resulting in its $175 million Utah Allocated Requested EBA Recovery were due to:

   ($52.6 million) decrease from a special contract customer adjustment,

[2] CONFIDENTIAL RMP Attachment B – RMP Painter Workpapers and Exhibit 5-1-2023, tab TABLE 1.
[3] CONFIDENTIAL RMP Attachment C - Webb Exhibits and Workpapers 3-15-2022, tab TABLE 1.

$.5 million increase from Utah Situs Resource adjustment,
$2 million increase from 2021 EBA Collection True-Up,
($.6 million) decrease from 2022 EBA Final Order Adjustment,
$ 5 million increase from accrued interest through June 30, 2023.

7. As a result of the 2021 General Session of the 64th Legislature, Utah Code 54-7-13.5 was revised to expressly authorize the Commission to allow interim rate treatment of EBAC subject to the Commission's authority to later order a refund or surcharge. The Code was also amended to limit the annual review and final Commission order to 300 days after the Company's annual application filing date. The Company filed its annual EBA report on May 1, 2023.

   On June 29, 2023, the Commission approved the Company's request for an interim rate to recover the application requested amount of $175 million in allowed energy balancing account deferred costs (EBAC) effective July 1, 2023.[4]

8. The Company included PTCs in its confidential Attachment B workpapers presented with Mr. Painter's direct testimony as allowed by Commission order in the 2020 GRC, Docket No. 20-035-04. Actual generation from PTC eligible generation wind facilities was less than expected in 2022, resulting in an approximately $10 million increase in the Company's requested deferral as detailed in Daymark's report.

   The Company's requested 2022 deferral recovery calculates an EBAC reduction of $4.7 million from the inclusion of PTCs. This decrease resulted from 1) the actual SG allocation percent difference from the EBA deferral year and the 2020 GRC base, and 2) an increase in the federal PTC rate of $.01 per kWh of reported eligible wind plant generation.

[4] Docket No. 23-035-01, June 29, 2023, Commission Order approving interim rates.

The 2022 deferral year was the second year with PTCs included in the EBA and the second year of unrealized wind generation. As detailed in Daymark's report, the Company's requested 2021 Deferral Period recovery included an estimated $10.9 million in recovery of unrealized PTCs, including accrued interest. [5] Continued under-performance of the inherently variable wind facilities could demonstrate an overreliance on forecast PTCs expected to offset capital costs.

9. The Division provided Daymark with a scope of work to perform. The Division asked Daymark to review variants of actual Net Power Cost (NPC) versus Base NPC, outages, PTCs, natural gas and power transactions, a high-level review of Energy Imbalance Market (EIM) benefits, and changes to energy risk management policies. The results of this review are provided in Daymark's separately issued Testimony, Executive Summary, and 2023 EBA Audit Report.[6]

10. Based on its report, Daymark recommends a $7.3 million reduction, including accrued interest, to the Company's requested deferral on a Utah allocated basis, incorporating:

    a. $.8 million decrease to EBAC, including interest, for replacement power losses from 3 avoidable outages at the Craig and Dave Johnson plants.

    b. $6.5 million decrease to EBAC, including interest, for losses associated with power physical trades that were deemed to be imprudent due to the nature of the transactions and the Company's insufficient analysis to support the trade purpose.

[5] Daymark Exhibits 2.0, 2.2, and Confidential Exhibit 2.3.
[6] Ibid.

The Division recommends reducing the Company's proposed recovery of $175 million by $7.3 million resulting in a Division-recommended adjusted total of $167.8 million, as follows:

May 2023 Requested Deferral	$175,029,815
Total Outage Adjustment	($753,447)
Total Outage Adjustment - Accrued Interest	(25,235)
Total Hedging Trade Adjustment	($6,284,307)
Total Hedging Trade Adjustment - Accrued Interest	(201,386)
Net Adjustment	($7,264,376)
Net Adjusted DPU Total Recommended Recovery	**$167,765,439**

11. The Company outlined in testimony that extreme weather events and drought conditions contributed to the increased purchased power and natural gas fuel expenses in the deferral year.[7] The Division found that during these weather events, the Company did not economically dispatch its coal facilities to displace more extremely high purchase power and natural gas prices. In response to the Division's request for information the Company detailed that coal supply and coal reserve challenges limited the Company's ability to utilize its lower cost coal plants fully to reduce these high costs that contributed to the large EBA deferral.[8]

The Idaho Public Utilities Commission (Idaho Commission) annually reviews Idaho's equivalent of Utah's EBA account, the Company's Idaho Energy Cost Adjustment

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[7] Docket No. 23-035-01, Direct Testimony of Jack Painter, Page 15

[8] DPU Exhibit 1.7 Dir, RMP DPU Data Request Response 17.2.

Mechanism (ECAM). On May 31, 2023, the Idaho Commission issued its final order in its review and approval of the Company's ECAM 2022 results. At the recommendation of Commission Staff, to ensure that the Company was dispatching its coal fleet on a least cost, efficient basis, the Idaho Commission directed the Company to investigate and prepare a report on the issues causing the extraordinarily high NPC in 2022. The Company's report is due at the end of the calendar year 2023. The Idaho Commission reserved its prudency determination and its ability to adjust the 2022 ECAM NPC during its next ECAM review period.[9]

The Division would benefit from this report and has requested the Company provide it when completed. As this report will not be available until the end of 2023, the Division requests the ability to review and provide any related 2022 deferral year adjustment recommendations from this report during the next EBA audit expected to be filed in May 2024. It is unclear whether the Company prudently managed its generation facilities during the high-cost weather events, leading to higher net power costs. Further investigation is required if the Division is to understand and evaluate the prudency of coal plant supply, dispatch, and the expenses that created the largest deferral requested since the adoption of the EBA.

To assist in the Division's understanding of the Company's Coal generation and related issues, the Division requests the following be included in the Company's Utah 2023 EBA filing, anticipated to be filed in May 2024.

1) Company presented workshops to discuss the modeling, inputs, and forecasting of the following topics, including how these topics are modeled in Aurora:

    a. Coal contracting;
    b. Coal dispatch;
    c. Day-ahead and Real-time (DA/RT) Adjustment;
    d. Wind forecasting;

[9] DPU Exhibit 1.7 Dir, Idaho Public Utilities Commission, CASE No. PAC-E-23-09, Order No. 35801.

e. Short-term transmission; and
f. Extended Day-Ahead Market/EIM.

2) Forecasted and actual generation at each coal plant.

3) Details on coal consumed per plant, and price of coal consumed for the month at each plant with an explanation for variances in forecasted generation greater than 10 percent from the forecast on a monthly and annual basis.