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Division of Public Utilities
UTAH DEPARTMENT OF COMMERCE

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Preliminary Review – Interim Rate Recommendation

To: Public Service Commission of Utah

From: Utah Division of Public Utilities

Chris Parker, Director
Brenda Salter, Assistant Director
Doug Wheelwright, Utility Technical Consultant Supervisor
Gary Smith, Utility Technical Consultant

Date: May 27, 2025

Re: **Docket No. 25-035-01,** Rocky Mountain Power's Application for Approval of the 2025 Energy Balancing Account – Interim Rate Request.

Recommendation (Approval With Conditions)

The Division of Public Utilities (Division or DPU) has conducted a preliminary review of Rocky Mountain Power's (Company or RMP) May 1, 2025, Energy Balancing Account (EBA) filing and its request for interim rates.

The Division recommends the Commission approve an interim rate collection based on the Company's calculated adjusted deferral amount of $471,615,308, and consistent with prior years' filings, a collection period of 12 months, from July 1, 2025, through June 30, 2026.

Background

On May 1, 2025, the Company filed its annual report for the EBA. In its Application, the Company requested an interim rate increase effective July 1, 2025, based on its calculated 2024 deferral year recovery of $471.6 million.[1] This requested deferral amount is the largest requested EBA recovery and is over 420% ($381 million) more than that requested for EBA deferral year 2021. The 2021 deferral year was the first year the EBA filing used the 2020 EBA Base (EBA Base or Base) set in the 2020 General Rate Case (2020 GRC).

[1] Direct Testimony of Jack Painter, Page 2, Lines 42 – 52.

DPU TABLE 1

EBA Recent History [2]

Docket No	Deferral Period (Calendar Yr)	Total Deferral ($m)	Collection (Yrs)	Effective Date	Ending Date
25-035-01	2024	$471.6	1.00	7/1/2025	6/30/2026
24-035-01	2023	$455.0	2.00	7/1/2023	6/30/2026
23-035-01	2022	$175.8	1.00	7/1/2023	6/30/2024
22-035-01	2021	$90.1	1.17	5/1/2022	6/30/2023
EBA BASE Reset in Docket 20-035-04					
21-035-01	2020	$1.7	1.00	3/1/2022	2/28/2023
20-035-01	2019	$36.8	1.00	3/1/2021	2/28/2022
19-035-01	2018	$17.3	1.00	4/1/2020	2/28/2021

The 2024 total-Company adjusted actual Net Power Cost (NPC) was approximately $2.6 billion.[3] The Company allocated $1.18 billion to Utah customers[4] based on the established Commission ordered method. This amount is over $551 million more than the $624 million NPC Base set in the 2020 GRC. After accounting for all variances in the Commission approved EBA items, the 2024 EBA deferral totaled $474.9 million (before the inclusion of the Company's interest, credits, and adjustments), as shown below in DPU TABLE 2.

[2] All information as filed by Rocky Mountain Power in the referenced docket number.
[3] Direct Testimony of Jack Painter, Page 5, Lines 91 – 92.
[4] Direct Testimony of Jack Painter, CONFIDENTIAL RMP Painter Workpapers 5-1-2025, 2.1.

DPU TABLE 2

Total EBA Deferrable Before Interest, Credits, and Adjustments [5]

Utah Allocated Actual NPC	$	1,175,313,526
Utah Allocated Base NPC		624,146,199
NPC Variance	**$**	**551,167,327**
Utah Allocated Actual Wheeling Revenue	$	(89,025,428)
Utah Allocated Base Wheeling Revenue		(50,632,163)
Wheeling Revenue Variance	**$**	**(38,393,265)**
Utah Allocated Actual PTC	$	(120,337,780)
Utah Allocated Base PTC		(106,227,616)
PTC Variance	**$**	**(14,110,164)**
Actual Utah Sales (MWh)		26,070,633
Base Utah Sales		24,837,388
Sales Variance		1,233,245
Base NPC Collection Variance	**$**	**(23,752,126)**
Combined Impact on Total Deferrable EBA	**$**	**474,911,772**

This $474.9 million in EBA deferral costs is calculated as the difference between the actual NPC, Production Tax Credits (PTC), and wheeling revenue allocated to Utah based on the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol), and the base NPC, PTCs, and wheeling revenue, established in the 2020 GRC. Collectively, NPC, PTCs, and wheeling revenue components are defined in the Company's EBA tariff, Schedule 94, as Energy Balancing Account Costs (EBAC).[6]

The Company's $471.6 million requested EBA recovery, on a Utah allocated basis, comprised the following components: $474.9 million in total EBA deferable (as detailed in DPU TABLE 2), less a net credit of $40.1 million (total credits and adjustments), and $36.8 million in interest expense (as detailed in RMP's Table 1 below).[7]

[5] Direct Testimony of Jack Painter, CONFIDENTIAL RMP Painter Workpapers 5-1-2025, Table 1.
[6] Direct Testimony of Jack Painter, Page 5, Lines 71 – 88.
[7] Direct Testimony of Jack Painter, Page 4, Line 64, Table 1.

Table 1
Annual EBA Calculation

Calendar Year 2024 EBA Deferral		*Exhibit RMP___(JP-1) Reference*
Actual EBA ($/MWh)	$ 37.05	*Line 6*
Base EBA ($/MWh)	18.81	*Line 12*
$/MWh Differential	**$ 18.24**	
Utah Sales (MWh)	26,070,633	*Line 5*
EBA Deferrable*	$ 474,911,772	*Line 14*
Special Contract Customer Adjustment*	(24,903,951)	*Line 17*
Utah Situs Resource Adjustment*	9,220,126	*Line 18*
Total Deferrable	$ 459,227,947	*Line 19*
2023 EBA Collection True-Up	$ 238,367	*Line 25*
2024 EBA Final Order Adjustment	(24,244,080)	*Line 26*
Interest Accrued through December 31, 2024	12,324,881	*Line 27*
Interest Accrued January 1, 2025 through March 31, 2025	5,995,373	*Line 29*
Interest Accrued April 1, 2025 through June 30, 2025	6,144,341	*Line 30*
Interest Accrued through Rate Effective Period July 1, 2025 through June 30, 2026	12,376,556	*Line 31*
EVIP Revenue	(51,052)	*Line 24*
2023 PTC Update	(397,024)	*Line 23*
Requested EBA Recovery	**$ 471,615,308**	*Line 32*

** Calculated monthly*

Mr. Painter's testimony provided the following reasons for the Company's increases in NPC and the EBA deferred amount:

1) decreased coal generation and coal fuel expense compared to the 2020 Base. The lack of coal fuel supply and generation resulted in the reliance on more expensive replacement power and lower wholesale sales;[8]

2) increased reliance on market power purchases at higher average market prices resulted in the largest component of the EBA's 2024 total deferral[9] and the largest deviation in NPC from the 2020 Base

[8] Direct Testimony of Jack Painter, Page 18, Line 334 and Page 21, Lines 378 – 393.
[9] Direct Testimony of Jack Painter, Page 18, Line 334 and Page 20, Lines 363 – 377.

3) increased natural gas fuel expense due to higher average prices than assumed in Base and the conversion of the Jim Bridger Units 1 and 2 to natural gas;[10]

4) decreased hydro generation due to the decommissioning of the Klamath river facilities (Copco #1, Copco #2, Iron Gate, and JC Boyle); [11]

5) very low wholesale sales volumes (lowest since the base was set in 2020), [12] and

6) January 2024 Martin Luther King Jr. holiday weekend storm event.[13]

DPU TABLE 3 below is the 2024 actual NPC results compared to the EBA Base set in the 2020 GRC. The values are Utah allocated actual annual NPC expense and revenue deviations from the 2020 base.[14] The combined natural gas and purchased power expenses increased the 2024 Utah allocated deferral by $509 million. Wholesale sales revenues were less than half the amount set in the 2020 Base.

DPU TABLE 3

	% DIFFERENCE 2024 vs 2020 Base	**$ DIFFERENCE 2024 vs 2020 Base**	**ACTUAL $ 2024**	**BASE $ 2020**
TOTAL Utah Allocated NPC	**88.31%**	**$551,167,327**	$1,175,313,526	$624,146,199
Wholesale Sales Revenue	**-50.62%**	**$49,708,877**	(48,484,047)	(98,192,924)
Purchased Power Expense	**143.16%**	**$380,143,194**	645,678,828	265,535,634
Coal Fuel Expense	**-9.12%**	**($23,834,749)**	237,442,166	261,276,915
Natural Gas Expense	**97.58%**	**$128,454,421**	260,098,415	131,643,994
Wheeling and Other Expense	**26.13%**	**$16,695,584**	80,578,164	63,882,580

DPU TABLE 4 below provides a comparison of the Company's total actual 2024 system generation deviations from the 2020 Base.[15] The values reflect the Company's

[10] Direct Testimony of Jack Painter, Page 18, Lines 334 - 443.
[11] Ibid.
[12] Ibid.
[13] Ibid.
[14] Direct Testimony of Jack Painter, CONFIDENTIAL RMP Painter Workpapers 5-1-2025.
[15] Direct Testimony of Jack Painter, CONFIDENTIAL RMP Painter Workpapers 5-1-2025.

underperforming assets and the increasing dependence on market transactions to meet load requirements. The Company's 2024 actual market purchases were 49% more than the 2020 Base. Wholesale Sales generation was 72% less than the 2020 Base. Coal and hydro generation were significantly lower than 2020 Base amounts.

DPU TABLE 4

	% DIFFERENCE 2024 vs 2020 Base	MWh DIFFERENCE 2024 vs 2020 Base	ACTUAL MWh 2024	BASE MWh 2020
TOTAL NPC MWh	**-3.06%**	**(2,067,191)**	65,554,823	67,622,014
Wholesale Sales Gen. (MWh)	**-72.12%**	**(5,078,582)**	1,963,687	7,042,269
Purchased Power Gen. (MWh)	**49.15%**	**6,786,979**	20,594,559	13,807,579
Coal Generation (MWh)	**-35.13%**	**(9,869,234)**	18,224,834	28,094,068
Natural Gas Gen. (MWh)	**17.43%**	**2,514,406**	16,942,474	14,428,068
Wind Generation (MWh)	**-6.02%**	**(461,477)**	7,204,159	7,665,637
Hydro Generation (MWh)	**-28.62%**	**(1,037,866)**	2,588,796	3,626,662

DPU TABLE 5 is a comparative table of NPC components for 2024 and 2023 actual results. Most of the $61 million increase was due to changes in Wholesale Sales Revenues (a 37% decrease in just one year) and Purchased Power.

DPU TABLE 5

	% DIFFERENCE 2024 vs 2023	$ DIFFERENCE 2024 vs 2023	ACTUAL $ 2024	ACTUAL $ 2023
TOTAL Utah Allocated NPC $	**5.48%**	**$61,095,985**	$1,175,313,526	$1,114,217,542
Wholesale Sales Revenue	**-36.63%**	**$28,030,702**	(48,484,047)	(76,514,749)
Purchased Power Expense	**3.76%**	**$23,405,553**	645,678,828	622,273,276
Coal Fuel Expense	**-3.66%**	**($9,013,299)**	237,442,166	246,455,465
Natural Gas Expense	**4.32%**	**$10,776,791**	260,098,415	249,321,624
Wheeling and Other Expense	**10.86%**	**$7,896,238**	80,578,164	72,681,926

DPU TABLE 6 compares the 2024 actual NPC and its components to 2023 amounts. The Company was able to increase gas plant generation to accommodate some of the 17% decrease in coal generation that was in part due to the Jim Bridger gas conversion of Units 1 and 2.

DPU TABLE 6

	% DIFFERENCE 2024 vs 2023	MWh DIFFERENCE 2024 vs 2023	ACTUAL MWh 2024	ACTUAL MWh 2023
TOTAL Company MWh	**1.63%**	**1,048,978**	65,554,823	64,505,845
Wholesale Sales Generation (MWh)	**-23.95%**	**(618,288)**	1,963,687	2,581,975
Purchased Power Generation (MWh)	**9.82%**	**1,841,441**	20,594,559	18,753,118
Coal Generation (MWh)	**-16.98%**	**(3,726,188)**	18,224,834	21,951,022
Natural Gas Generation (MWh)	**20.59%**	**2,892,562**	16,942,474	14,049,912
Wind Generation (MWh)	**6.71%**	**452,765**	7,204,159	6,751,394
Hydro Generation (MWh)	**-13.72%**	**(411,603)**	2,588,796	3,000,399

Coal supply constraints, which began at the end of calendar year 2022, extended into mid-2024[16] causing an increase in the Company's natural gas generation and replacement power purchases. The 2024 decrease in coal generation is also due in part to the loss of approximately 1060 megawatts of coal generation due to the conversion of Jim Bridger's Units 1 and 2.

Hydro generation decreased in 2024 due to dry conditions and the decommissioning of Copco #1, Copco #2, Iron Gate, and JC Boyle hydro generation facilities on the Klamath River.[17]

[16] Direct Testimony of Jack Painter, Page 21, Lines 379 – 380.
[17] Direct Testimony of Jack Painter, Page 18, Lines 334 - 443.

Wholesale generation and sales declined to the lowest volumes since the base was set in 2020 due to the lack of available company resource capacity. [18]

Market purchases increased in 2024 to the highest totals to date, continuing the trend of increasing market purchases and market dependency. [19]

DPU TABLE 7 below provides a four-year deferral comparison of actual average annual prices including the average annual price presumed in the 2020 Base.[20] Natural gas generation expense and purchased power prices were significantly higher than initially presumed in the 2020 Base. Even though the average annual price for market purchases was slightly lower than in 2023, the average annual price of wholesale sales for resale continues to lag with the gap widening between the purchase and sell price.

DPU TABLE 7

			DEFERRAL YEAR		BASE
	2024	**2023**	**2022**	**2021**	**2020**
Wholesale Resale ($/MWh)	54.31	67.41	61.40	37.48	31.69
Purchased Power ($/MWh) [21]	73.62	76.94	67.46	65.80	43.50
Coal Generation ($/MWh)	28.94	25.39	20.46	19.88	21.45
Natural Gas Gen. ($/MWh)	33.75	39.61	44.61	26.40	20.73

Mr. Painter's testimony included Table 2 below, which detailed a NPC analysis and average pricing of NPC components.

[18] Ibid.
[19] Ibid.
[20] Direct Testimony of Jack Painter, CONFIDENTIAL RMP Painter Workpapers 5-1-2025.
[21] The Company calculated the average cost of market purchases at $69/MWh:

Table 2
Net Power Cost Reconciliation

Net Power Costs $	Actual	Base	Variance
Wholesale Sales	106,724,822	223,178,425	(116,453,603)
Purchased Power	1,421,024,233	600,690,780	820,333,453
Coal	527,475,934	602,628,592	(75,152,657)
Gas	571,862,902	299,136,021	272,726,880
Other	183,618,646	151,248,344	32,370,302
Total $	**$2,597,256,893**	**$1,430,525,312**	**$1,166,731,582**
Net Power Costs GWh	**Actual**	**Base**	**Variance**
Wholesale Sales	1,964	7,042	(5,079)
Purchased Power	20,595	13,808	6,787
Coal	18,225	28,094	(9,869)
Gas	16,942	14,428	2,514
Other	9,793	11,292	(1,499)
Total GWh	**63,591**	**60,580**	**3,011**
Net Power Costs $/MWh	**Actual**	**Base**	**Variance**
Wholesale Sales	$54.35	$31.69	$22.66
Purchased Power	$69.00	$43.50	$25.50
Coal	$28.94	$21.45	$7.49
Gas	$33.75	$20.73	$13.02
Other	$18.75	$13.39	$5.36
Total $/MWh	**$40.84**	**$23.61**	**$17.23**

In this table, the average price of Purchased Power was listed as $69.00/MWh.[22] Based on the Company's filed information, the Division calculated the average price of Purchased Power as $73.62/MWh in DPU TABLE 8.

[22] Direct Testimony of Jack Painter, Page 18, Line 334.

DPU TABLE 8

	2024 ACUTAL AVERAGE $/MWh	
	DPU Calculated	**RMP Calculated**
Purchased Power Total ($)	1,516,268,744	1,421,024,233
Purchased Power Total (MWh)	20,594,559	20,595,000
Average ($/MWh)	$73.62	$69.00

The Division is unclear how Mr. Painter's total purchased power amount of $1,421,024,233 was derived. The Division used the value of $1,516,268,744 found in Tab (2.5) of Mr. Painter's Excel workbook entitled "CONFIDENTIAL RMP Painter Workpapers 5-1-2025.xlsx."

Mr. Painter reported that the Company's filing contained changes to the EBA deferral calculations that have not been previously included or approved by the Commission including:

1) the inclusion of Electric Service Schedule 60 (EVIP) revenues,[23]
2) a PTC Update, and
3) the inclusion of the interest expected to accrue through the rate effective period of July 1, 2025, through June 30, 2026.[24]

For the first time, the Company included revenues collected through Electric Service Schedule 60 from Company-owned electric vehicle charging infrastructure that began operating in October 2024. The inclusion of these revenues was agreed to under the Electrical Vehicle Infrastructure Program (EVIP), Docket No. 20-035-34. The 2024 EVIP revenues totaled $51,052. Also included is an adjustment to update 2023 PTCs, totaling

[23] Direct Testimony of Jack Painter, Page 3, Lines 53 – 55 and Page 15, Lines 298 - 306.
[24] Direct Testimony of Jack Painter, Page 3, Lines 53 – 57.

$397,024. The Division found that the Company did not provide sufficient details or calculations for this adjustment.

The Company included over $12.3 million for interest that would accrue in its proposed collective period of July 1, 2025, through June 30, 2026 (Collection Period Interest).[25] Prior to the 2024 EBA filing, the Company had included interest occurring in the deferral year up to the Commission's ordered interim rate effective date, but had not included the amount of interest that accrues during the collection period in its application.

The carrying charge for the EBA has been established as the rate set in Electric Service Schedule 300, which is updated annually with a rate effective date of April 1. Accordingly, the carrying charge would change once during the Company's proposed 12-month collective period, leaving a period of three months that an assumed interest rate would be required to be estimated. In principle, the Division is opposed to the use of assumed numbers in a regulatory construct (aside from the established base amounts allowed in rates) whose designed purpose is to true up actual results. However, the Division is not opposed to the inclusion of the Collection Period Interest in the EBA interim rates, so long as the Company can demonstrate that such inclusion would not cause any interest compounding or cause additional interest expense to unnecessarily accrue.

As detailed in Mr. Meredith's work papers, the proposed 12-month recovery of the 2024 deferral was spread across customer rate classes.[26] The rate spread, rate design, and billing determinants appear consistent with the method approved in the 2020 GRC. Mr. Meredith also included revisions to Electric Schedule 94 that included changes to the list of FERC accounts. The Division has requested additional information on these changes and will include any pertinent findings in the Division's final report.

The Division has performed a preliminary review of the Company's application for cost recovery. Issues presented herein are provided in support of the Division's recommendation

[25] Direct Testimony of Jack Painter, Page 8, Lines 139 – 158.
[26] Direct Testimony of Robert Meredith, Exhibit RMP___(RMM-3).

on the Company's filing and proposed interim rate. The Division will have additional details, comments, and recommendations in its final report.

Although the Division has performed a broad review of the current filing, it makes no judgment regarding the entirety or accuracy of the information. Confidential DPU Exhibit 1 summarizes the Division's comparison of the Company's current Application and supporting documents with the prior year's filing. The variations, issues, and questions discovered during this initial review, not mentioned in this interim rate report, but recorded in DPU Exhibit 1, were determined to be immaterial to the Company's EBA interim rate request.

Conclusion

Based on the overall body of information as filed and the Division's experience with EBA filings and audits, the Company has made a prima facie showing that the proposed interim rate appears consistent with prior years' filings and is more likely to reflect actual power costs than current Base rates. [27]

The Division recommends the Company's requested $471,615,308 in deferred NPC be collected over one year on an interim rate basis, from July 1, 2025, through June 30, 2026. The Division's recommendation conditionally includes the Company's proposed $12.3 million of Collection Period Interest. The Company's application did not provide a comparative analysis of its proposed changes to its current method. The Division requests the Company include in its rebuttal testimony, a comparative analysis (including comparative calculations) demonstrating any increase in interest costs compared to its current method, allowing the Division to more fully evaluate the effects of the Company's proposal.

Finally, because the Company included a 2023 PTC Update without sufficient detail or calculations, the Division requests that the Company provide additional details and calculations for the 2023 PTC Update. The Company should include full details and calculations for all adjustments included with its annual EBA application.

[27] Utah Code Ann. § 54-7-13.5 (2)(k)(iii)(B)

cc: Jana Saba, Rocky Mountain Power
Michele Beck, Office of Consumer Services