Rocky Mountain Power
Docket No. 26-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Jack Painter

May 2026

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company").

A. My name is Jack Painter, and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Net Power Cost Adviser.

I. QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I received a Bachelor of Arts degree in Business Administration with a Finance major from Washington State University in 2007. I have been employed by PacifiCorp since 2008 and have held positions in the regulation and jurisdictional loads departments. I joined the regulatory net power costs group in 2019 and assumed my current role as a Net Power Cost Adviser in 2024.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the public service commissions in Utah, Idaho, Wyoming, Oregon, Washington, and California.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony presents and supports the Company's calculation of the Energy Balancing Account ("EBA") deferral for the 12-month period from January 1, 2025, through December 31, 2025 ("Deferral Period"). More specifically, I provide the following:

- Details supporting the calculation of the Company's request to recover $190.6 million for excess EBA-related costs including interest, an adjustment for sales made to a special contract customer, Utah situs-assigned resource

adjustments included in the EBA, an adjustment to reflect the Public Service Commission of Utah's ("Commission") order in the 2025 EBA,[1] a reduction to include the remaining over-collected balance from the 2024 EBA,[2] and an adjustment to credit the EBA with 33 percent of Schedule 60 revenues from the Electric Vehicle Infrastructure Program ("EVIP");[3] and

- Discussion of the main differences between adjusted actual net power costs ("Actual NPC") for calendar years 2025 and 2024 and net power costs in rates ("Base NPC").

Q. Are any other witnesses presenting testimony specifically for the EBA and Electric Service Schedule No. 94 ("Schedule 94") in this case?

A. Yes. Company witness Kenneth Lee Elder, Jr., Director, Pricing & Tariff Policy, provides testimony on the proposed Schedule 94 rates.

III. SUMMARY OF THE EBA DEFERRAL CALCULATION

Q. Please summarize the Company's EBA application.

A. The Company's application requests recovery of $190.6 million in deferred costs, comprised of $193.7 million of EBA-related costs, a credit of $9.9 million for sales made to a special contract customer, a $7.9 million adjustment for Utah situs-assigned resources, a credit of $4.5 million to reflect the 2025 EBA Order, a $13.0 million reduction to reflect the remaining balance from the 2024 EBA, a credit of approximately $0.3 million for EVIP Schedule 60 revenue, and approximately $16.7

[1] *Rocky Mountain Power's Application for Approval of the 2025 Energy Balancing Account*, Docket No. 25-035-01, Order (Feb. 27, 2026) ("2025 EBA Order").
[2] *Rocky Mountain Power's Application for Approval of the 2023 Energy Balancing Account*, Docket No. 24-035-01, Order (Feb. 25, 2025) ("2024 EBA Order").
[3] *Rocky Mountain Power's Application for Approval of Electrical Vehicle Infrastructure Program*, Docket No. 20-035-34, Order Approving Settlement Stipulation (Dec. 20, 2021) ("2021 EVIP Order").

million of interest. The Company proposes to collect the deferred balance over 12 months beginning July 1, 2026.

Q. Are there any changes to the EBA deferral calculation?

A. Yes. Changes have been included as part of the EBA calculation for base rates, which were updated in the 2024 General Rate Case ("2024 GRC") and became effective April 25, 2025.[4]

IV. EBA DEFERRAL CALCULATION

Q. Please describe the calculation of the EBA deferral included in this filing.

A. Table 1 below provides a summary of the total EBA deferral and a breakdown of the individual components of the EBA. Additionally, Exhibit RMP___(JP-1) presents the detailed calculation of the EBA deferral on a monthly basis.

Table 1
Annual EBA Calculation

Calendar Year 2025 EBA Deferral		*Exhibit RMP___(JP-1) Reference*
Actual EBA ($/MWh)	$ 28.98	*Line 6*
Base EBA ($/MWh)	21.78	*Line 12*
$/MWh Differential	**$ 7.20**	
Utah Sales (MWh)	26,441,140	*Line 5*
EBA Deferrable*	$ 193,655,162	*Line 14*
Special Contract Customer Adjustment*	(9,912,402)	*Line 17*
Utah Situs Resource Adjustment*	7,867,402	*Line 18*
Total Deferrable	$ 191,610,162	*Line 19*
2024 EBA Collection True-Up	$ (13,020,077)	*Line 24*
2025 EBA Final Order Settlement	(4,510,000)	*Line 25*
EVIP Revenue	(266,586)	*Line 23*
Interest Accrued through December 31, 2025	6,597,453	*Line 26*
Interest Accrued January 1, 2026 through March 31, 2026	2,446,524	*Line 28*
Interest Accrued April 1, 2026 through June 30, 2026	2,608,886	*Line 29*
Interest Accrued through Rate Effective Period July 1, 2026 through June 30, 2027	5,092,561	*Line 30*
Requested EBA Recovery	**$ 190,558,923**	*Line 31*

** Calculated monthly*

[4] *Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposal Electric Service Schedules and Electric Service Regulations,* Docket No. 24-035-04, Order (April 25, 2025) ("2024 GRC Order").

The EBA deferral of $190.6 million is calculated as the difference between the Actual NPC, Production Tax Credits ("PTCs") and wheeling revenue and the Base NPC, PTCs and wheeling revenue, as established in the 2020 general rate case ("2020 GRC") and 2024 general rate case ("2024 GRC").[5] The calculation of the monthly amount debited or credited into the EBA Deferral Account is based on the following formula:

$$EBA\ Deferral_{Utah,month} = \left[\left(Actual\ EBAC_{\frac{Utah,month}{MWh}} - Base\ EBAC_{\frac{Utah,month}{MWh}}\right) \times Actual\ MWh_{Utah,month}\right]$$

Q. What revenue requirement components are included in the EBA deferral calculation?

A. The EBA deferral calculation consists of three revenue requirement components: NPC, PTCs and wheeling revenue. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses, and wheeling expenses, less wholesale sales revenue. PTCs are credits the Company receives for generation at certain Company-owned wind facilities that are included as an offset to the Company's federal income taxes and reduce net power costs for rate-making purposes. Wheeling revenue includes amounts booked to Federal Energy Regulatory Commission ("FERC") account 456.1 and revenues from transmission of electricity of others. Collectively, these three components are known in the Company's EBA tariff, Schedule 94, as Energy Balancing Account Costs ("EBAC").

[5] *Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations,* Docket No. 20-035-04, Order (Dec. 30, 2020) ("2020 GRC Order"); see also 2024 GRC Order.

Q. How are the Utah-allocated Actual NPC calculated?

A. Utah-allocated Actual NPC are calculated in three steps. First, unadjusted actual NPC are established on a total-Company basis. Second, adjustments are made to the unadjusted actual NPC to apply certain regulatory adjustments and to remove out-of-period accounting entries. Third, the adjusted total-Company Actual NPC are allocated to Utah based on the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol.

Q. What were the total-Company adjusted Actual NPC for the Deferral Period and how were they determined?

A. The total-Company adjusted Actual NPC in the Deferral Period were approximately $2.203 billion. This amount captures all components of NPC as defined in the Company's GRC proceedings and modeled by the Company's power cost production model. Specifically, it includes amounts booked to the following FERC accounts:

- Account 447 – Sales for resale, excluding on-system wholesale sales and other revenues that are not modeled in GRID
- Account 501 – Fuel, steam generation; excluding fuel handling, start-up fuel (gas and diesel fuel, residual disposal) and other costs that are not modeled in GRID
- Account 503 – Steam from other sources
- Account 509 – Allowances
- Account 547 – Fuel, other generation
- Account 555 – Purchased power, excluding the Bonneville Power Administration residential exchange credit pass-through if applicable

Account 565 – Transmission of electricity by others

Q. Does the Company have any updates to the potential FERC accounting change that was noted in your testimony in the 2023 EBA proceeding?

A. Yes. On June 29, 2023, the FERC issued Order No. 898 (Docket No. RM21-11-000), Accounting and Reporting Treatment of Certain Renewable Energy Assets, to change the accounting required for certain types of costs that have been previously booked to FERC Account 555 to be booked to FERC account 509.[6]

Q. Does FERC Order No. 898 impact the current EBA?

A. Yes. The change from FERC account 555 to FERC account 509 for these costs becomes effective January 1, 2025.

Q. Did the Company update the accounts listed in Schedule 94 as recommended by the Division of Public Utilities in the 2023 EBA?

A. Mr. Elder presents the Company's revisions to Schedule 94 which includes an update to the accounts listed for inclusion or exclusion from the EBA as recommended by Division witness Gary Smith.

Q. What adjustments are made to Actual NPC and why are they needed?

A. The Company adjusts Actual NPC to reflect the ratemaking treatment of several items, including:

- Out of period accounting entries booked in the Deferral Period that relate to operations prior to implementation of the EBA in October 2011;
- Revenue from a contract related to the Leaning Juniper wind resource;
- Revenue for wheeling expense reimbursement from Orchard Wind QF;

[6] *File Rule*, 183 FERC ¶ 61,205, Docket No. RM21-11-000 (Jun. 29, 2023) *available at* https://www.ferc.gov/media/order-no-898.

- Costs for situs-assigned resources/programs in Utah, Oregon, Washington, California and Idaho;
- Situs assignment of Reasonable Energy Price adjustments to QF's;
- Coal inventory adjustments to reflect coal costs in the correct period; and
- Legal fees related to fines and citations included in the cost of coal.

Additional details regarding each of these adjustments and the impact on NPC are provided in Additional Filing Requirement 15.

Q. What allocation methodology did the Company use to calculate the EBA Deferral Account balance?

A. The 2020 GRC set the Base NPC effective January 1, 2021, in the 2020 GRC Order, and the 2024 GRC set the Base NPC effective April 25, 2025, in the 2024 GRC Order, using the Commission Order Method, which was originally approved by the Commission in Docket No. 09-035-15. Exhibit RMP___(JP-1) calculates the EBA deferral using the Commission Order Method for the entire Deferral Period.

Q. Does the calculation of the EBA deferral include carrying charges?

A. Yes. In accordance with the Commission's orders dated March 2, 2011, and February 16, 2017, in Docket No. 09-035-15, carrying charges accrue on the monthly EBA deferral. Effective January 1, 2020, the carrying charge is the customer deposit rate for Residential and Non-residential Deposits in Electric Service Schedule No. 300. Carrying charges accrue monthly during the Deferral Period, the review period, and will continue to accumulate during the collection period. The estimated impact of carrying charges during the rate effective period of July 1, 2026 through June 30, 2027 is included in the EBA calculation and the supporting calculation is provided in

Additional Filing Requirement 21.

Q. Did the Commission approve inclusion of interest during the collection period?

A. Yes. Carrying charges have always accrued during the collection period. Prior to the 2025 EBA, they were not included in the EBA filing and were instead recovered in a subsequent EBA. In the 2025 EBA, the Company requested to include the collection period carrying charges in the 2025 EBA amount requested at the time of application, which was approved by the Commission.[7]

Q. Please describe the impact of the special contract customer(s) in the EBA.

A. A special contract customer pays rates specified in the contract and is not subject to new EBA rates approved on or after December 1, 2016. The NPC associated with serving the special contract customer are embedded in Actual NPC. As Utah tariff customers benefit from the special contract remaining on the Company's system and paying a portion of the total revenue requirement, the EBA deferral amount associated with the special contract customer is shared among Utah tariff customers. Additionally, a certain portion of the sales to a special contract customer are at a price different than NPC in base rates, and an adjustment is made to the EBA in which the Utah tariff customers share the variance between the contract price and Base NPC with the Company.

Q. Please describe the adjustment for sales made to a special contract customer.

A. Per the stipulation in Docket No. 16-035-33, the EBA includes an adjustment for certain sales made to the special contract customer.[8] The adjustment calculates monthly the

[7] 2025 EBA, Order Approving Interim Rates, (Jun. 30, 2025) at 6.

[8] *In the Matter of Rocky Mountain Power for Approval of an Energy Service Contract with Kennecott Utah Copper, LLC*, Docket No. 16-035-33, Settlement Stipulation (Oct. 7, 2026) and Rocky Mountain Power's Addendum to the October 7, 2016 Settlement Stipulation (Aug. 7, 2016).

difference between the average monthly contract price paid and NPC in base rates ("Special Contract Differential"). The Special Contract Differential is then multiplied by the megawatt-hour ("MWh") sales to the special contract customer to calculate the dollar amount of the variance. The difference is then subject to a symmetrical deadband of $350,000. For the 2026 EBA, the adjustment for sales made to a special contract customer is a $9.9 million credit.

V. TREATMENT OF SITUS-ASSIGNED RESOURCES

Q. What are situs-assigned resources?

A. Situs-assigned resources are renewable resources that the Company acquired on behalf of either individual states or customers in order to serve part or all of their energy needs. Both the costs and benefits for these resources are situs-assigned to the state of origin. Non-participating states should not bear higher costs for these resources.

Q. Which resources or programs are considered situs-assigned?

A. The Utah situs-assigned resources or programs are Pavant III Solar for the Utah Subscriber Solar Program, Electric Service Schedule No. 136 Transition Program for Customer Generators ("Schedule 136"), Electric Service Schedule No. 137 Net Billing Service for Customer Generators ("Schedule 137"), Amor IX/Soda Lake Geothermal and Castle Solar under Electric Service Schedule No. 32 ("Schedule 32"), and Cove Mountain Solar 2, Graphite Solar, Appaloosa Solar 1A and 1B, Rocket Solar, Horseshoe Solar, and Faraday Solar under Electric Service Schedule No. 34 ("Schedule 34"). Situs-assigned resources or programs in the Company's remaining jurisdictions are Black Cap Solar, Old Mill Solar, the Oregon Solar Incentive Plan, California Electric Service Schedule No. 136 Net Billing, and Idaho Electric Service Schedule

No. 136 Net Billing.

Q. How does the Company treat situs-assigned resources in the EBA?

A. On a monthly basis, the Company uses either the actual cost or the mark-to-market calculation for NPC allocation purposes, whichever is lower. This treatment will ensure that non-participating states will not pay costs higher than actual costs and only the costs that are above market will be situs-assigned to state of origin.

Q. Are there any exceptions to the changes the Company has made?

A. Yes. Black Cap Solar in Oregon is a Company leased resource that has continued the sole use of the mark-to-market calculation because there is no Power Purchase Agreement ("PPA") costs in NPC. Additionally, because the Utah Subscriber Solar Program and both Utah Schedule 32 and Schedule 34 resources, excluding Elektron Solar, are paid entirely by the respective customers, the lower of actual cost or market results in zero PPA costs.

Q. Please describe the Utah Situs-Assigned Resource Adjustment.

A. The Utah Situs-Assigned Resource Adjustment accounts for the Utah situs costs of certain resources and expenses, namely the Utah Subscriber Solar Program, Schedule 136, Schedule 137, the Western Energy Imbalance Market ("WEIM") Body of State Regulators ("BOSR") fees charged for commission related work as a participant in the WEIM, and the Western Power Pool ("WPP") Committee of State Representatives ("COSR") and Western Resource Adequacy Program ("WRAP") implementation costs and program coordination services.

Q. Please describe the Utah Subscriber Solar Program.

A. The Commission approved the "Subscriber Solar Program Rider - Optional" Electric

Service Schedule No. 73 ("Schedule 73"), effective March 21, 2016, which enables participating Utah customers to purchase electricity from a specific utility-scale solar resource.[9] Customers can elect to purchase blocks of energy at a set amount each month, and the value of any excess, unused block energy is rolled forward to future months. Participating blocks of energy purchased are subject to rates specific to Schedule 73 and are not subject to the EBA adjustment rate schedule changes (Schedule 73, Special Condition 15).

Q. Please describe the situs-assigned adjustment to the EBA for the Utah Subscriber Solar Program Resource.

A. Under the stipulation in Docket No. 15-035-61, the solar resource is included as a Utah-situs resource in net power costs.[10] The generation costs of the solar resource are compared to the generation charges paid by solar subscriber customers and the difference is either recovered from or credited back to Utah customers through the EBA. In addition, there are no load adjustments and no change in allocation factors due to the program. The EBA adjustment for Subscriber Solar is a cost of $0.2 million.

Q. Please describe Schedule 136 Transition Program and Schedule 137 Net Billing for Customer Generators.

A. In Docket No. 14-035-114, the Commission approved Schedule 136, effective November 14, 2017.[11] In Docket No. 17-035-61, the Commission approved Schedule

[9] *In the Matter of the Application of Rocky Mountain Power for Approval of its Subscriber Solar Program (Schedule 73)*, Docket No. 15-035-61, Tariff Approval Letter from the Commission (March 21, 2016).
[5] *In the Matter of the Application of Rocky Mountain Power for Approval of its Subscriber Solar Program (Schedule 73)*, Docket No. 15-035-61, Order Approving Amended Settlement Agreement, Exhibit A at 7 (Oct. 21, 2015).
[11] *In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program*, Docket No. 14-025-114, Order Approving Proposed Tariff Sheets and Allowing Additional Comment Period on Limited Issues (Nov. 14, 2017).

137, effective October 30, 2020.[12] Both programs enable eligible customers to offset part or all of their own electrical requirements with self-generation and receive export credits for energy fed back to the electric grid, which measures the difference between the electricity supplied by the Company and the electricity generated by an eligible customer-generator.

Q. Please describe the situs-assigned adjustment to the EBA for the Schedule 136 and Schedule 137 costs.

A. The cost difference between export credits to eligible customers and the market value of the exports is recovered from Utah customers through the EBA using the lower of cost or market treatment described above. The EBA adjustment for Schedule 136 costs is $4.6 million and for Schedule 137 costs is $2.9 million.

Q. Please describe the situs-assigned adjustment to the EBA for the fees associated with the WEIM BOSR, WPP COSR, and WPP WRAP.

A. The WEIM BOSR fee supports the BOSR's expenses and supports the body's goal that consistent and informed regulator engagement on regional market operations and developments is crucial to efficient and sustainable markets that deliver public benefits. The Utah allocated cost in the EBA is $12,258. The WPP WRAP and its state represented committee, COSR, is the regional resource adequacy initiative that is being implemented by many utilities and power producers across the west to ensure that the region is better able to plan for its regional resource adequacy needs. The Utah allocated cost in the EBA is $55,523 for the WRAP and $11,195 for the COSR. The WEIM BOSR and WPP WRAP fees were approved by the Commission for inclusion in the

[12] *Application of Rocky Mountain Power to Establish Export Credits for Customer Generated Electricity,* Docket No. 17-035-61, Order (Oct. 30, 2020).

EBA in Docket No. 22-035-01. The costs included in this EBA filing are for January 1, 2025 through April 24, 2025. Beginning April 25, 2025, these items are now included in Base NPC rates as part of the 2024 GRC and will no longer be included in the EBA.

Q. What is the WPP COSR?

A. "The Committee of State Representatives (COSR) is a standing committee of the Western Resource Adequacy Program (WRAP), a first-of-its-kind reliability program in the West operated by the Western Power Pool (WPP). The WRAP tariff was approved by the Federal Energy Regulatory Commission (FERC) at the beginning of 2023, and the COSR was established soon after in April 2023 in accordance with the WRAP Bylaws. The COSR aims to support state and provincial engagement in the WRAP and share those valuable perspectives on pertinent program matters. The COSR will advise the WPP Board of Directors, Program Review Committee (PRC), Resource Adequacy Participants Committee (RAPC), any working groups or task forces, and the Federal Energy Regulatory Commission (FERC) on matters related to WRAP governance, program design, and operations. The COSR is composed of one representative from each state or provincial jurisdiction that regulates at least one Participant. State and provincial representatives are nominated by the Chair or President of their respective public utility commissions and may include representatives from the state or provincial energy offices or state or provincial funded consumer advocates. The COSR operates in a public setting and welcomes other regional stakeholders to attend committee meetings to better foster engagement and collaboration."[13]

[13] More information on the COSR is available at: https://www.westernenergyboard.org/cosr/.

Q. Please describe the situs-assigned adjustment to the EBA for Schedule 32 and Schedule 34 excess generation purchases.

A. Schedule 32 and Schedule 34 are unique retail service options available to any customer who would otherwise qualify for Electric Service Schedule Nos. 6, 8, or 9 that desires to receive all or part of its electricity from a renewable energy facility. This allows the Company to meet its customers' renewable energy goals while protecting the Company's other customers from the financial impacts of another customer's preference. Purchase power agreement costs and generation from renewable energy facilities for the customer are removed from NPC in the EBA and any excess generation is purchased at Electric Service Schedule No. 37 avoided costs rates. Total-Company Schedule 32 and Schedule 34 excess generation costs in the EBA are $11.5 million.

Q. Please describe the new adjustment to include Schedule 60 revenues in the EBA associated with the EVIP.

A. The Company's EVIP was established through a Settlement Stipulation that was approved by the Commission on December 29, 2021.[14] The Settlement Stipulation specified that thirty-three percent of the revenue collected from Company-owned electric vehicle charging infrastructure through Schedule 60 would be credited to Utah customers in the EBA.[15] Therefore, $266,586 is included in the EBA as a credit in accordance with the terms of the Settlement Stipulation.

[14] *Application of Rocky Mountain Power for Approval of Electrical Vehicle Infrastructure Program,* Docket No. 20-035-34, Order Approving Settlement Stipulation (Dec. 29, 2021).
[15] *Application of Rocky Mountain Power for Approval of Electrical Vehicle Infrastructure Program* Docket No. 20-035-34, Settlement Stipulation at 8-9 (Nov. 6, 2021).

Q. Please describe why there is a variance in the EVIP revenue credited in the EBA and the EVIP revenue from Attachment A in the Company's EVIP report.

A. The variance between the two is simply timing and is caused because the EVIP revenue in Attachment A is accounted for on a cash basis while the EVIP revenue in the EBA is accounted for an accrual basis.

VI. DIFFERENCES IN NPC

Q. Please explain the Base NPC the Company used to calculate the NPC component of the EBA deferral.

A. The Base NPC for the 2025 EBA is comprised of two components. First the 2020 GRC established Base NPC from January 1, 2021 through April 24, 2025 and set total-Company Base NPC at $23.61/MWh using a 12-month test period from January 2021 through December 2021. Second, the 2024 GRC updated Base NPC effective April 25, 2025 and set total-Company Base NPC at $29.03/MWh using a 12-month test period from January 2025 through December 2025. Based upon a normalized forecast with perfect foresight, actual operating and market conditions will vary from Base NPC.

Q. On a total-Company basis, what was the difference between Actual NPC and Base NPC established in the 2024 GRC for the Deferral Period?

A. On a total-Company basis, Actual NPC for the Deferral Period was $34.30/MWh, approximately $5.27/MWh more than Base NPC established in the 2024 GRC for the Deferral Period. Table 2 provides a high-level summary of the difference between Base NPC established in the 2024 GRC and Actual NPC by category on a total-Company basis.

Table 2
Net Power Cost Reconciliation (2025 Actual NPC and 2024 GRC Base NPC)

Net Power Costs $/MWh	Actual	Base	Variance
Wholesale Sales	$44.81	$76.42	($31.61)
Purchased Power	$51.31	$62.26	($10.96)
Coal	$30.35	$31.80	($1.46)
Gas	$34.38	$42.29	($7.91)
Other	$17.22	$18.49	($1.28)
Total $/MWh	**$34.30**	**$29.03**	**$5.27**
Net Power Costs GWh	**Actual**	**Base**	**Variance**
Wholesale Sales	4,036	3,771	265
Purchased Power	18,743	23,335	(4,592)
Coal	23,289	21,519	1,770
Gas	15,375	14,688	687
Other	10,846	10,775	71
Total GWh	**64,218**	**66,547**	**(2,329)**
Net Power Costs $	**Actual**	**Base**	**Variance**
Wholesale Sales	180,849,296	288,174,390	(107,325,094)
Purchased Power	961,619,745	1,452,895,054	(491,275,309)
Coal	706,769,032	684,383,693	22,385,340
Gas	528,571,922	621,172,172	(92,600,251)
Other	186,744,213	199,270,874	(12,526,661)
GRC Order Adjustments	-	(737,514,376)	737,514,376
Total $	**$2,202,855,615**	**$1,932,033,026**	**$270,822,589**

Q. Please explain the primary differences in 2025 Actual NPC and Base NPC established in the 2024 GRC.

A. From an accounting perspective, and as shown in Table 2 above, Actual NPC differed from Base NPC due to a $107 million reduction in wholesale sales, a $491 million decrease in purchased power expense, a $22 million increase in coal fuel expense, a $93 million increase in natural gas expense, and a $13 million decrease in wheeling

and other expenses. Overall, the differences are due to lower market prices for purchased power, lower natural gas prices and increased coal supply leading to increased natural gas and coal generation volumes, and decreased load.

Q. On a total-Company Utah-adjusted basis, what was the $/MWh variance between the current Deferral Period and calendar year 2024?

A. From a $/MWh perspective, Actual NPC for the Deferral Period was $34.30/MWh while calendar year 2024 Actual NPC was $40.84/MWh, a decrease of $6.54/MWh or 16.0 percent. Table 3 below displays Utah-adjusted Actual NPC for 2025 and 2024 with a high-level summary of the differences, by cost category, on a total-company basis.

Table 3
Net Power Cost Reconciliation (2025 Actual NPC and 2024 Actual NPC)

Net Power Costs $/MWh	2025	2024	Variance
Wholesale Sales	$44.81	$54.35	($9.54)
Purchased Power	$51.31	$69.00	($17.69)
Coal	$30.35	$28.94	$1.41
Gas	$34.38	$33.75	$0.62
Other	$17.22	$18.75	($1.53)
Total $/MWh	**$34.30**	**$40.84**	**($6.54)**
Net Power Costs GWh	**2025**	**2024**	**Variance**
Wholesale Sales	4,036	1,964	2,072
Purchased Power	18,743	20,595	(1,852)
Coal	23,289	18,225	5,064
Gas	15,375	16,942	(1,567)
Other	10,846	9,793	1,053
Total GWh	**64,218**	**63,591**	**627**
Net Power Costs $	**2025**	**2024**	**Variance**
Wholesale Sales	180,849,296	106,724,822	74,124,474
Purchased Power	961,619,745	1,421,024,233	(459,404,489)
Coal	706,769,032	527,475,934	179,293,098
Gas	528,571,922	571,862,902	(43,290,980)
Other	186,744,213	183,618,646	3,125,566
Total $	**$2,202,855,615**	**$2,597,256,893**	**($394,401,278)**

Q. What are the main drivers of decreased NPC from 2024 to 2025?

A. For 2025, the main drivers of decreased NPC were increased coal fuel supply and lower natural gas market prices and power market prices from their 2023 peaks.

Q. What was the change in output for the Company's coal generating facilities in 2025?

A. In 2025, the Company's coal fuel supply stabilized after experiencing constraints and force majeure claims from 2022-2024. Coal generating facilities increased their output from approximately 18 thousand gigawatt-hours ("GWh") in 2024 to 23 thousand GWh in 2025 as shown in Table 3 above leading to reductions in purchased power volumes

and natural gas generation output.

Q. How did lower market power prices decrease NPC in 2025?

A. The average price of market purchases decreased from $115/MWh in 2024 to $80/MWh in 2025. When combined with the increase in coal generation output above, market purchase volumes decreased by 2,716 GWh from 2024 to 2025. The overall impact to 2025 NPC was a reduction of $509 million in market purchase costs.

VII. ADJUSTMENTS RELATED TO FINAL EBA RATES

Q. Please explain the adjustment to reflect the 2025 EBA Order.

A. The 2025 EBA Order adopted the settlement stipulation between the Company and the Division of Public Utilities with an adjustment of $4.51 million as a reduction to the EBA.

Q. Please explain the adjustment related to the 2024 EBA.

A. After collection of the authorized EBA in Docket No. 24-035-01 through Schedule 94 concluded, $13,020,077 was over-collected and will be credited to customers in this EBA.

VIII. CONCLUSION

Q. Please summarize your testimony.

A. The EBA deferral of $190.6 million, including interest for the calendar year 2025 Deferral Period was accurately calculated in compliance with the EBA tariff and previous Commission orders.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(JP-1)
Docket No. 26-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Jack Painter

Monthly EBA Deferral Calculation

May 2026

Utah Energy Balancing Account
January 1, 2025 - December 31, 2025
Exhibit 1 - Commission Order Calculation Method (Dynamic Annual Allocation Factor

Line No.		Reference	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Total
Actual: Utah Allocated															
1	NPC	(2.1)	$ 91,861,687	$ 86,812,739	$ 73,272,670	$ 68,316,335	$ 70,603,590	$ 86,179,812	$ 112,444,022	$ 106,271,298	$ 90,567,045	$ 69,286,978	$ 76,485,682	$ 74,810,888	$ 1,006,912,746
2	PTC	(9.1)	(13,678,589)	(13,599,961)	(14,428,961)	(11,539,132)	(10,602,426)	(8,825,965)	(8,890,482)	(7,312,940)	(7,267,838)	(12,427,417)	(15,335,408)	(22,705,489)	(146,614,608)
3	Wheeling Revenue	(4.1)	(8,404,883)	(8,628,193)	(7,259,110)	(4,841,509)	(5,689,303)	(7,016,803)	(8,582,462)	(8,125,073)	(6,586,413)	(6,102,702)	(4,978,235)	(17,929,841)	(94,144,529)
4	Total	∑ Lines 1:3	$ 69,778,214	$ 64,584,585	$ 51,584,599	$ 51,935,694	$ 54,311,860	$ 70,337,044	$ 94,971,078	$ 90,833,286	$ 76,712,794	$ 50,756,859	$ 56,172,039	$ 34,175,558	$ 766,153,610
5	Jurisdictional Sales	(5.2)	2,303,221	1,939,829	2,061,580	1,874,104	2,056,241	2,458,108	2,711,847	2,642,817	2,173,398	1,938,586	2,031,821	2,249,587	26,441,140
6	Actual Utah $/MWh	Line 4 / Line 5	**$ 30.30**	**$ 33.29**	**$ 25.02**	**$ 27.71**	**$ 26.41**	**$ 28.61**	**$ 35.02**	**$ 34.37**	**$ 35.30**	**$ 26.18**	**$ 27.65**	**$ 15.19**	**$ 28.98**
Base: Utah Allocated															
7	NPC	(3.1)(3.2)	$ 52,896,516	$ 49,963,481	$ 51,232,250	$ 45,519,770	$ 47,326,041	$ 55,485,829	$ 112,824,170	$ 122,456,740	$ 66,813,844	$ 63,667,317	$ 68,554,411	$ 87,332,458	$ 824,072,829
8	PTC	(9.1)	(8,852,301)	(8,852,301)	(8,852,301)	(9,368,121)	(11,431,398)	(11,431,398)	(11,431,398)	(11,431,398)	(11,431,398)	(11,431,398)	(11,431,398)	(11,431,398)	(127,376,208)
9	Wheeling Revenue	(4.1)	(4,219,347)	(4,219,347)	(4,219,347)	(5,241,134)	(9,328,280)	(9,328,280)	(9,328,280)	(9,328,280)	(9,328,280)	(9,328,280)	(9,328,280)	(9,328,280)	(92,525,418)
10	Total	∑ Lines 7:9	$ 39,824,867	$ 36,891,833	$ 38,160,602	$ 30,910,516	$ 26,566,363	$ 34,726,151	$ 92,064,492	$ 101,697,062	$ 46,054,166	$ 42,907,639	$ 47,794,733	$ 66,572,780	$ 604,171,202
11	Jurisdictional Sales	(5.2)	2,087,756	1,833,770	1,924,709	1,903,767	2,233,834	2,521,580	2,968,570	2,866,350	2,408,658	2,260,617	2,277,359	2,452,428	27,739,395
12	Base Utah $/MWh	Line 10 / Line 11	**$ 19.08**	**$ 20.12**	**$ 19.83**	**$ 16.24**	**$ 11.89**	**$ 13.77**	**$ 31.01**	**$ 35.48**	**$ 19.12**	**$ 18.98**	**$ 20.99**	**$ 27.15**	**$ 21.78**
Deferral:															
13	$/MWH Differential	Line 6 - Line 12	$ 11.22	$ 13.18	$ 5.20	$ 11.48	$ 14.52	$ 14.84	$ 4.01	$ (1.11)	$ 16.18	$ 7.20	$ 6.66	$ (11.95)	$ 7.20
14	EBA Deferrable	Line 5 * Line 13	**$ 25,843,247**	**$ 25,559,045**	**$ 10,710,281**	**$ 21,506,791**	**$ 29,857,559**	**$ 36,485,002**	**$ 10,868,354**	**$ (2,932,921)**	**$ 35,156,861**	**$ 13,961,529**	**$ 13,530,385**	**$ (26,890,972)**	**$ 193,655,162**
15	Special Contract Customer Adjustment Subject to Deadband	(7.1)	(1,900,740)	(2,581,267)	(312,528)	(150,073)	(1,189,745)	(1,200,982)	(725,154)	(144,289)	(179,065)	(1,320,482)	(1,041,083)	483,007	(10,262,402)
16	Symmetrical Deadband	Docket 16-035-33	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000
17	Total Special Contract Adjustment	Line 15 - Line 16	(1,550,740)	(2,581,267)	(312,528)	(150,073)	(1,189,745)	(1,200,982)	(725,154)	(144,289)	(179,065)	(1,320,482)	(1,041,083)	483,007	(9,912,402)
18	Utah Situs Resource Adjustment	(8.1)	445,194	615,721	275,666	919,655	958,781	864,199	1,024,925	443,894	585,080	790,471	498,300	445,516	7,867,402
19	Total Incremental EBA Deferral	∑ Lines 14 and Lines 17:18	**$ 24,737,701**	**$ 23,593,500**	**$ 10,673,419**	**$ 22,276,373**	**$ 29,626,595**	**$ 36,148,219**	**$ 11,168,126**	**$ (2,633,317)**	**$ 35,562,876**	**$ 13,431,518**	**$ 12,987,602**	**$ (25,962,449)**	**$ 191,610,162**
Energy Balancing Account:															
20	Monthly Interest Rate	Note 1	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	
21	Beginning Balance	Prior Month Line 27	$ -	$ 20,270,499	$ 43,996,720	$ 54,867,427	$ 77,426,590	$ 107,449,776	$ 144,139,428	$ 155,953,577	$ 153,987,775	$ 190,296,514	$ 204,586,012	$ 218,496,235	$ -
22	Incremental Deferral	Line 19	24,737,701	23,593,500	10,673,419	22,276,373	29,626,595	36,148,219	11,168,126	(2,633,317)	35,562,876	13,431,518	12,987,602	(25,962,449)	191,610,162
23	EVIP Revenue	Docket 20-035-34	(12,216)	(9,955)	(22,197)	(14,204)	(18,447)	(23,371)	(27,670)	(28,288)	(27,038)	(28,512)	(27,176)	(27,512)	(266,586)
24	2024 EBA Collection True-Up	Docket 24-035-01												(13,020,077)	(13,020,077)
25	2025 EBA Final Order Settlement	Docket 25-035-01	(4,510,000)												(4,510,000)
26	Interest	Line 20 * (Line 21 + 50% x Line 22)	55,014	142,677	219,484	296,993	415,038	564,805	673,693	695,802	772,901	886,491	949,798	924,756	6,597,453
27	**Ending Balance**	∑ Lines 21:26	**$ 20,270,499**	**$ 43,996,720**	**$ 54,867,427**	**$ 77,426,590**	**$ 107,449,776**	**$ 144,139,428**	**$ 155,953,577**	**$ 153,987,775**	**$ 190,296,514**	**$ 204,586,012**	**$ 218,496,235**	**$ 180,410,952**	**$ 180,410,952**
28	Interest Accrued January 1, 2026 through March 31, 2026	Line 27 * (1 + 1.0540% / 12) ^ 3 - Line 27													2,446,524
29	Interest Accrued April 1, 2026 through June 30, 2026	Line 27 and 28 * (1 + 1.05680% / 12) ^ 3 - Line 27 and 28													2,608,886
30	Interest Accrued through Rate Effective Period July 1, 2026 through June 30, 2027														5,092,561
31	**Requested EBA Recovery**	∑ Lines 27:30													**$ 190,558,923**

Notes:
1 Interest rate is from Electric Service Schedule No. 300 due to Docket No. 09-035-15/Order Issued November 14, 2019.