REDACTED
Rocky Mountain Power
Docket No. 24-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Jack Painter

May 2024

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 Specialist.

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 Specialist in 2020.

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, 2023, through December 31, 2023 ("Deferral Period"). More specifically, I provide the following:

- Details supporting the calculation of the Company's request to recover $455.0 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 2023 EBA,[1] and an adjustment to include the remaining uncollected balance from the 2022 EBA;[2]

- Discussion of the main differences between adjusted actual net power costs ("Actual NPC") and net power costs in rates ("Base NPC"); and
- Discussion about the Company's participation in the Western Energy Imbalance Market ("WEIM") with the California Independent System Operator ("CAISO") and the benefits from the WEIM that are passed through to customers.

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 Robert M. Meredith, 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 $455.0 million in deferred costs, comprised of $450.9 million of EBA-related costs, a credit of $41.4 million for sales made to a special contract customer, a $1.7 million adjustment for Utah situs-assigned resources, a credit of $0.2 million to reflect the 2023 EBA Order, a $1.1 million adjustment to reflect the remaining balance from the 2022 EBA, and approximately $42.9 million of interest. As discussed by Mr. Meredith, the Company proposes to

[1] *Rocky Mountain Power's Application for Approval of the 2023 Energy Balancing Account*, Docket No. 23-035-01, Order (Feb. 23, 2024) ("2023 EBA Order").
[2] *Rocky Mountain Power's Application for Approval of the 2022 Energy Balancing Account*, Docket No. 22-035-01, Order (Jan. 9, 2023).

collect the deferred balance over 24 months beginning July 1, 2024.

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

A. Yes. Changes have been included as part of the EBA calculation for the following items:

- Inclusion of the expense associated with export credits from Electric Service Schedule No. 137 - Net Billing Service for customer owned generators.
- Inclusion of the interest accrued through the rate effective period from July 1, 2024 through June 30, 2026.
- An inclusion of an adjustment to reflect a $0.2 million reduction to the 2023 EBA to reflect the final Commission Order.
- A rollover of $1.1 million in unrecovered deferred balances that were previously approved for recovery in the 2022 EBA.

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 2023 EBA Deferral			Exhibit RMP___(JP-1) Reference
Actual EBA ($/MWh)	$	36.39	*Line 6*
Base EBA ($/MWh)		18.81	*Line 12*
$/MWh Differential	**$**	**17.58**	
Utah Sales (MWh)		25,678,773	*Line 5*
EBA Deferrable*	$	450,877,742	*Line 14*
Special Contract Customer Adjustment*		(41,446,176)	*Line 17*
Utah Situs Resource Adjustment*		1,721,691	*Line 18*
Total Deferrable		411,153,257	*Line 19*
2022 EBA Collection True-Up	$	1,073,739	*Line 23*
2023 EBA Final Order Adjustment		(153,260)	*Line 24*
Interest Accrued through December 31, 2023		8,965,067	*Line 25*
Interest Accrued January 1, 2024 through March 31, 2024		4,828,711	*Line 27*
Interest Accrued April 1, 2024 through June 30, 2024		4,884,089	*Line 28*
Interest Accrued through Rate Effective Period July 1, 2024 through June 30, 2026		24,201,822	*Line 29*
Requested EBA Recovery	**$**	**454,953,425**	*Line 30*

* Calculated monthly

The EBA deferral of $450.9 million is calculated as the difference between the Actual NPC, Production Tax Credits ("PTCs") and wheeling revenue and the Base NPC, PTC's and wheeling revenue, as established in the 2020 general rate case.[3] The calculation of the monthly amount debited or credited into the EBA Deferral Account is based on the following formula:

[3] *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).

$$EBA\ Deferral_{Utah,month} =$$

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

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").

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

$2.528 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 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.[4]

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

A. No. The change from FERC account 555 to FERC account 509 for these costs becomes

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

effective January 1, 2025.

Q. What costs will be affected by FERC's Order No. 898 beginning January 1, 2025?

A. The change in accounting affects the costs associated with greenhouse gas ("GHG") allowances that have been booked to FERC account 555 and historically included in the EBA in the Company's general ledger ("GL") accounts. GL account 546516 includes CA GHG costs which is currently listed in Schedule 94 and are included in the EBA. GL account 546515 includes WA GHG costs that are proposed to be included in this EBA and explained in detail further below in my testimony.

Q. Did the Company update Schedule 94 to include FERC 509 as recommended by the Division of Public Utilities in the 2023 EBA?

A. Mr. Meredith 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. However since no costs have been booked to FERC account 509, that account has not been added at this time. The Company will revise Schedule 94 to include FERC Account 509 once it has been implemented and contains costs, which will likely be the 2026 EBA, filed May 1, 2026, for deferred calendar year 2025 costs.

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;
- Buy-through of economic curtailment by interruptible industrial customers;

- Revenue from a contract related to the Leaning Juniper wind resource;
- Costs for situs-assigned resources/programs in Utah and Oregon;
- 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 Docket No. 20-035-04 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. While carrying charges have always accrued during the collection period, the Company has not previously included them in the initial EBA application. To reflect a more accurate rate design, the Company has calculated the estimated impact of carrying charges during the rate effective period of July 1, 2024 through June 30, 2026 and has included them in the EBA calculation.

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

A. The 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 the 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. The adjustment calculates monthly the 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 2024 EBA, the adjustment for sales made to a special contract customer is a $41.4 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 by a renewable resource. 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. There are currently nine resources or programs that are situs-assigned with five in Utah and four in Oregon. 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 under Electric Service Schedule No. 32 ("Schedule 32"), and Cove Mountain Solar 2, Graphite Solar, Appaloosa Solar 1A and 1B, and Rocket Solar under Electric Service Schedule No. 34 ("Schedule 34"). The Oregon situs-assigned resources or programs are Black Cap Solar, Old Mill Solar, Oregon Community Solar, and the Oregon Solar Incentive Plan.

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

A. The Company uses either the actual cost or the mark-to-market calculation, whichever is lower for NPC allocation purposes. 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 are paid entirely by the respective customers, the lower of actual cost or market results in zero PPA costs. While the PPA costs for the Utah Subscriber Solar Program and Schedule 32 and Schedule 34 are zero, there are specific program or contractual costs situs-assigned in the EBA discussed later in my testimony.

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, excess generation purchases from Schedule 32 and Schedule 34 customers, 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") 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 28, 2016, which enables participating Utah customers to purchase electricity from a specific utility-scale solar resource. 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.[5] 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 credit to customers of $0.3 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 15, 2017. In Docket No. 17-035-61, the Commission approved Schedule 137, effective October 31, 2020. 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.

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[2] *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).

Q. Have Schedule 137 costs been included in previous EBA filings?

A. No. The Company found that the costs included in the EBA for customer generators only included Schedule 136. In April 2023, a correction was made to include Schedule 137 costs in the NPC calculation. A prior period adjustment was made in December 2023 to record Schedule 137 costs that occurred prior to the deferral period in this EBA.

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 $1.0 million and zero for Schedule 137 costs under the lower of cost or market treatment.

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

A. The WEIM BOSR fee supports the BOSR's expenses and support 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 $42,011. The WPP WRAP 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 $764,505. These fees were approved by the Commission for inclusion in the EBA in Docket No. 22-035-01.

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

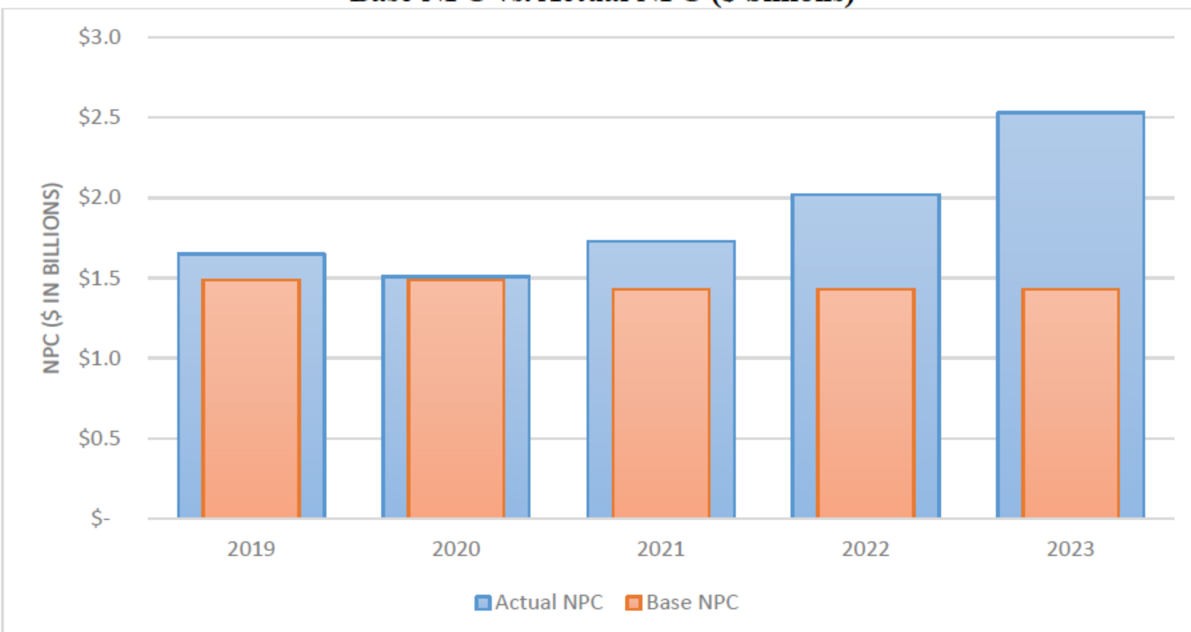
A. Schedule 32 and Schedule 34 are unique retail service options available to any customer who would otherwise qualify for Electric Service Schedule Nos. 6, 8, or 9 that desires to receive all or part of its electricity from a renewable energy facility. This allows the Company to meet its customers' 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. The situs-assigned costs for excess generation purchases in the EBA is $0.2 million.

VI. DIFFERENCES IN NPC

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

A. The Base NPC for the 2024 EBA were set in the 2020 GRC and became effective January 1, 2021. Base NPC used a test period of 12 months from January 2021 through December 2021 and set total-Company Base NPC at $1.431 billion. Based upon a normalized forecast and perfect operating conditions, circumstances have changed significantly since the Base NPC were established. Both higher market power and natural gas prices, shifts from base load resources to intermittent renewable energy resources, coal fuel supply constraints, extreme weather events, and drought have all contributed to current system operations that do not represent the forecast. The Company operates its system on a least cost economic dispatch model for its customers and it is important to note that Base NPC are set for ratemaking purposes only, not the management of actual system operations, nor would it be prudent to do so. Figure 1 below illustrates how Base NPC have been fairly static over time, while Actual NPC has increased significantly.

Figure 1
Base NPC vs. Actual NPC ($ billions)



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

A. On a total-Company basis, Actual NPC for the Deferral Period were $2.528 billion, approximately $1.098 billion more than Base NPC for the Deferral Period. Table 2 provides a high-level summary of the difference between Base NPC and Actual NPC by category on a total-Company basis.

Table 2
Net Power Cost Reconciliation ($ millions)

	TOTAL
Base NPC	**$ 1,431**
Increase/(Decrease) to NPC:	
Wholesale Sales Revenue	49
Purchased Power Expense	815
Coal Fuel Expense	(45)
Natural Gas Expense	257
Wheeling and Other Expense	22
Total Increase/(Decrease)	**1,098**
Total Company NPC Difference	**$ 1,098**
Adjusted Actual NPC	**$ 2,528**

Q. Please describe the primary differences between Actual NPC and Base NPC.

A. As shown in Table 2, Actual NPC were higher than Base NPC due to a $815 million increase in purchased power expense, a $257 million increase in natural gas expense, a $49 million decrease in wholesale sales revenue, and a $22 million increase in wheeling and other expenses, which were partially offset by a $45 million decrease in coal fuel expense.

Q. What are the main drivers of increased NPC in 2023?

A. For 2023, three main drivers increased NPC, coal fuel supply constraints and increased market power and natural gas prices, both of which are discussed with further detail in my testimony below. Coal supply constraints which began at the end of calendar year 2022, continued through 2023 and still impact the Company today. Market power prices and natural gas prices have risen sharply since 2021. These drivers have an overarching influence on all components of the Company’s actual system operations through its least cost economic dispatch model. Some of the more significant changes identified in 2023 are reduced wholesale sales volumes, reduced coal generation volumes, increased gas generation volumes compared to previous years and increased market purchases.

Q. Please explain the changes in wholesale sales revenue.

A. Wholesale sales volumes declined relative to Base NPC due to an increase in total Company load combined with coal supply constraints and decreases in renewable resource output and hydro generation. When actual market conditions differ from normalized forecast conditions in the power cost production model, the opportunities for the Company to sell excess generation to the market are limited. Additionally, as market power prices and loads increase simultaneously, wholesale sales volumes decrease as the Company serves its load through its own generation. Overall, the above market and system dynamics decreased wholesale sales revenue by $49 million compared to Base NPC. While the average price of actual wholesale market transactions, represented in the power cost production model as short-term firm and system balancing sales, was $81.97/MWh, or 156 percent higher than the average price in Base NPC, actual wholesale market volumes were 5,042 gigawatt-hours ("GWh"), or 75 percent, lower than Base NPC. In order to achieve a more accurate level of wholesale sales volumes, the Company will be proposing enhancements to its power cost production modeling in the upcoming general rate case.

Q. Please explain the changes in purchased power expense.

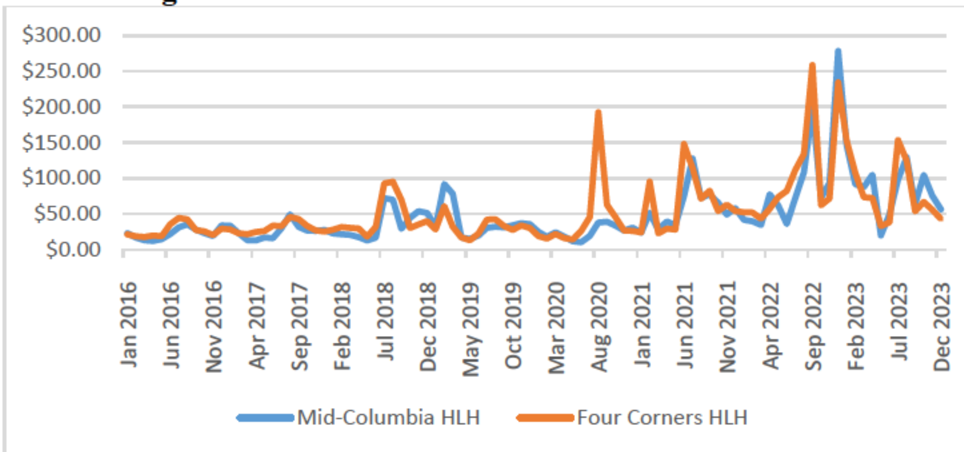
A. Overall, actual purchased power expense increased $815 million over Base NPC because the actual average price from market purchase transactions, represented in the power cost production model as short-term firm and system balancing purchases, significantly increased. On a dollar per megawatt-hour basis, actual market purchase transactions increased from $17.17/MWh in Base NPC to $116.40/MWh, or 578 percent and actual market purchase volumes increased by 4,250 GWh or 120 percent higher than Base NPC.

The average monthly price of market transactions at the Mid-Columbia and Four Corners market hubs has risen significantly since 2021. Between 2016 and 2020, the average monthly Heavy Load Hour ("HLH") market price at the Mid-Columbia market hub was $29.27/MWh and $35.11/MWh at the Four Corners market hub while the average monthly HLH market price in 2023 was $85.51/MWh and $81.12/MWh respectively. Table 3 and Figure 2 illustrate these significant market price increases impacting 2023 NPC.

Table 3
Average HLH Mid-Columbia & Four Corners Market Price

Year	Mid-C HLH Average	Four-C HLH Average
2016-2020	$29.27	$35.11
2021	$58.36	$65.42
2022	$92.75	$102.59
2023	$85.51	$81.12

Figure 2
Average HLH Mid-Columbia & Four Corners Market Price



Q. Please explain the changes in coal fuel expense.

A. As discussed in my testimony above, coal supply shortages, primarily at the Hunter and Huntington plants, that began in the fourth quarter of 2022 and extended through 2023, had a significant impact on the Company's coal generating resources and total system operations. Due to overall lower coal fuel availability, the Company had to adjust its overall system operations through increased natural gas resource output, increased purchased power, and reduced wholesale sales. Total coal fuel expense decreased because coal generation volume was 6,143 GWh, or 22 percent lower than Base NPC as presented in Table 4.

Table 4
Coal Generation

Year	Base GWh	Actual GWh	Variance	Percent
2021	28,094	31,590	3,496	12%
2022	28,094	28,391	297	1%
2023	28,094	21,951	(6,143)	-22%

The coal supply shortages also increased the average cost of coal generation from $21.45/MWh in Base NPC to $25.39/MWh in the Deferral Period. Overall, the lower generation volume results in a decrease of $45 million in coal fuel expense, but the coal supply limitations impacted all other aspects of the Company's system operations and net power costs in 2023 as previously explained.

Q. Please describe the changes in natural gas fuel expense.

A. With a reduction in coal generating resource output in 2023, the Company increased output at its natural gas generating resources when compared to previous years. While natural gas prices and the average cost of natural gas generation are higher than Base NPC, the price for operating the Company's natural gas generating resources was more economic than market power purchases on average. Overall, the total natural gas fuel expense in Actual NPC increased by $605 million compared to Base NPC primarily due to an increase in the average cost of natural gas generation from $20.73/MWh in Base NPC to $39.61/MWh in the Deferral period. Table 5 below shows how gas generation volumes have increased since 2020.

Table 5
Gas Generation

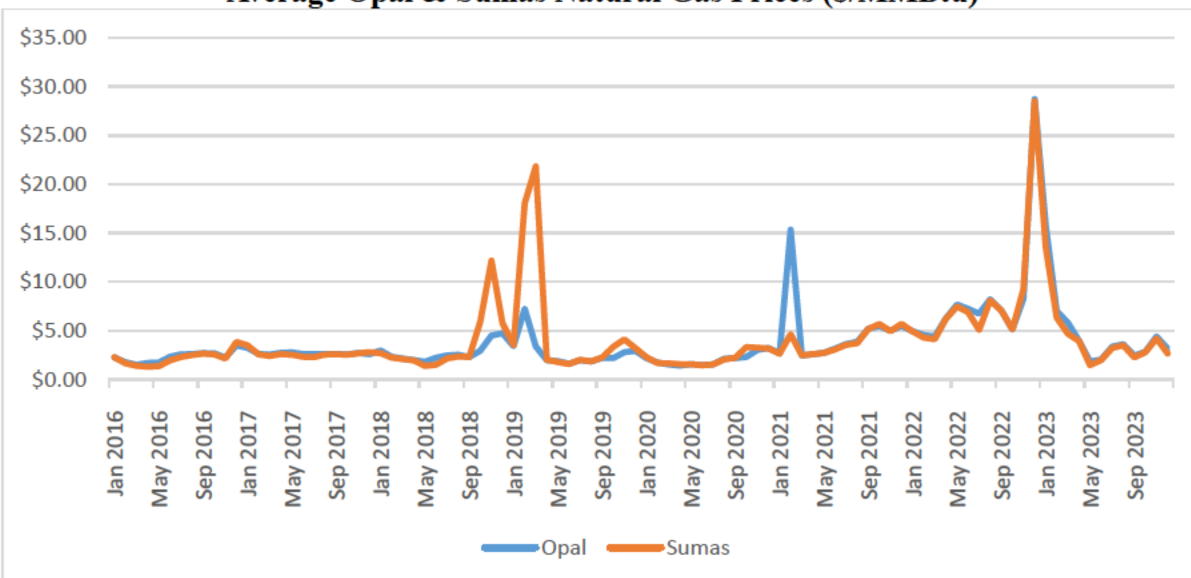
Year	Actual GWh
2020	12,042
2021	13,312
2022	13,686
2023	14,050

Like the significant increase in the average price of market power purchases discussed above, average natural gas prices have also seen a significant increase during the same timeframe. Table 6 and Figure 3 below illustrate these increases impacting 2023 NPC.

Table 6
Average Opal & Sumas Natural Gas Prices ($/MMBtu)

Year	Opal Average	Sumas Average
2016-2020	$2.51	$3.19
2021	$4.80	$3.91
2022	$8.27	$8.09
2023	$4.70	$4.22

Figure 3
Average Opal & Sumas Natural Gas Prices ($/MMBtu)



Q. Please describe how extreme weather events have impacted NPC.

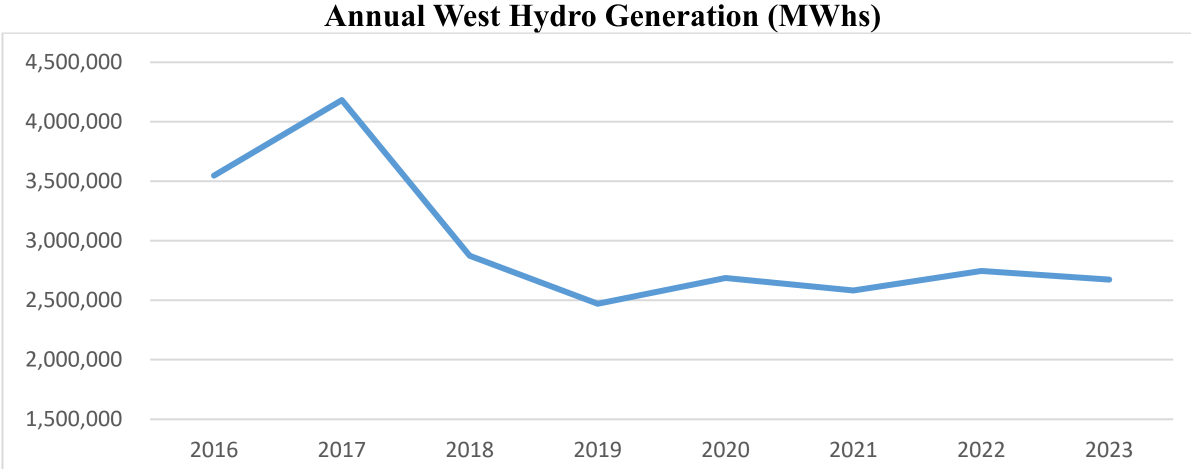
A. Ongoing drought in the West, which began in the summer of 2020, has continued to impact Actual NPC because it reduced the availability of the Company's hydro resources. In 2023, actual generation from the Company's hydro resources was 626 GWh (17 percent) lower than forecasted generation from Base NPC as shown in Table 7 below and needed to be replaced to meet customer demand.

Table 7
Hydro Generation

Year	Base GWh	Actual GWh	Variance	Percent
2021	3,934	3,037	(897)	-23%
2021	3,627	2,789	(838)	-23%
2022	3,627	2,936	(691)	-19%
2023	3,627	3,000	(627)	-17%

The estimated impact on total-Company NPC in 2023 due to decreased hydro MWhs caused by drought is $63 million. In the four years preceding the drought (2016-2019), average west hydro resource generation was 3.3 million MWhs while the average west hydro resource generation during the drought (2020-2023) was 2.7 million MWhs, a difference of 600 thousand MWhs, on average. Figure 4 below shows the decline over time.

Figure 4
Annual West Hydro Generation (MWhs)



Additionally, in December 2022, a historic winter cyclone event occurred across the majority of the United States, which impacted both market prices and natural gas prices, along with an increase in demand. The impacts of this event on both natural gas prices across the Company's delivery points and market power purchase prices were not only significant and elevated, but also carried over into January 2023. Table 8 and Table 9 below show the large variance between average January prices and the remaining average for the year prices between February and December at the Opal and Sumas natural gas hubs and Mid-Columbia and Four Corners market purchase power hubs.

Table 8
Opal and Sumas Average Monthly Price ($/MMBtu)

Month	Opal	Sumas
Jan	$15.85	$13.58
Feb - Dec	$3.68	$3.37

Table 9
Mid-Columbia and Four Corners Average Monthly Price ($/MWh)

Month	Mid-C HLH	Four-C HLH
Jan	$146.06	$152.35
Feb - Dec	$80.01	$74.64

VII. COAL SUPPLY CONSTRAINTS

Q. Please describe the many challenges the Company faced fueling its coal generating resources in 2023.

A. All of Utah's operating mines and some Wyoming mines experienced significant production difficulties and challenges in 2023 due to geological, logistical, and financial challenges. The most significant challenge was the mine fire that occurred at American Consolidated Natural Resources' ("ACNR") Lila Canyon mine. The mine had produced more than 25 percent of Utah's coal production in recent years and stopped production in September 2022. ACNR announced the permanent closure of the Lila Canyon mine in November 2023 after determining that it was not possible to safely remediate and operate the mine.

In 2023, all of PacifiCorp's Utah coal suppliers and a major Wyoming coal supplier operated under *force majeure* declarations that resulted in significant delivery shortfalls of PacifiCorp's contracted coal supply. Consequently, the Utah coal mines experienced a 35 percent decrease in coal production from 10.7 million tons in 2022 to 6.9 million tons. Table 10 below highlights recent Utah coal market production data.

Table 10

Utah Coal Production by Supplier (source MSHA)					
	TONS			Change	
	2021	**2022**	**2023**	**2022 v. 2023**	**%**
Bronco Utah Operations, LLC	1,170,988	1,062,707	798,023	(264,684)	-25%
Wolverine Fuels, LLC	6,845,083	6,425,241	5,477,050	(948,191)	-15%
ACNR Holdings, Inc.	3,470,644	2,281,289	159,240	(2,122,049)	-93%
Gentry Mountain Mining, LLC	512,951	599,770	419,592	(180,178)	-30%
Alton Coal Development, LLC	434,165	354,265	66,659	(287,606)	-81%
	12,433,831	10,723,272	6,920,564	(3,802,708)	-35%

Additionally, challenges in the U.S. coal market in 2022 due to historically low coal inventories and soaring natural gas prices led many utilities to increase coal purchases for generation and to restock depleted coal inventories. In many coal basins, coal pricing more than doubled in 2022 and remained high into 2023. This effect on coal pricing was exacerbated by the war in Ukraine, when many U.S. mines, including mines in Utah and Colorado, rushed to take advantage of high coal prices by exporting coal to Europe.

Q. What did the Company do to acquire additional coal supply in 2023?

A. The Company explored economic coal from possible sources. PacifiCorp contracted with a new supplier in 2023, Gentry Mountain Mining ("Gentry"), for additional coal supply for the Hunter plant. The Gentry coal supply agreements were designed to purchase all known economically-available Utah coal for use at the Utah plants. PacifiCorp continued to cooperate with the Hunter plant's co-owners to deliver coal from one of the plant co-owner's mine in Colorado. PacifiCorp even excavated a small amount of coal from the buried coal pile at the Gadsby plant, a converted natural gas plant in Salt Lake City, and delivered the coal to the Hunter plant. PacifiCorp also continued to transport coal from the Rock Garden safety pile to the Huntington plant. This activity continued through September 2023 when the Rock Garden inventory was completely depleted.

PacifiCorp also procured coal from the North Antelope Rochelle Mine ("NARM") in Wyoming's Powder River Basin for the first time for the Jim Bridger plant. Historically, Jim Bridger's coal has been supplied by the captive Bridger Coal Company mine and Lighthouse Resources' local Black Butte mine ("Black Butte"). PacifiCorp's deliveries from Black Butte were 0.88 million tons or [redacted] less than contracted in 2023. The shortfall occurred due to Black Butte's [redacted]. Black Butte mine declared *force majeure* in October 2023 [redacted]. Early in 2023, once the Black Butte delivery shortfall became apparent, PacifiCorp took steps to mitigate the shortfall. First, dispatch of the Jim Bridger plant was adjusted to account for the shortfall. Second, PacifiCorp contracted for the delivery of NARM coal which also required PacifiCorp to lease railcars. PacifiCorp received 0.33 million tons from NARM in 2023 to partially offset the reduction in Black Butte mine deliveries.

Q. How did the Company ensure existing coal suppliers in Utah did not suspend operations during 2023?

A. Bronco Utah Operations, LLC ("Bronco") operates the Emery mine in Utah. PacifiCorp signed a coal supply agreement with Bronco in 2020 which allowed the Company to purchase [redacted] tons per year for calendar years

2021-2024 for coal to the Hunter Plant. Bronco notified PacifiCorp in late 2022 that it was unable to supply coal to the Hunter Plant at the current contract price and needed a commitment longer than the remaining two years of the contract for it to make the necessary capital investment for a reliable supply of coal to the Hunter plant. PacifiCorp evaluated the economic effects of this request and determined to adjust the Bronco contract terms to allow Bronco to obtain the necessary financing.

To avoid the unfavorable cost impacts to PacifiCorp's customers resulting from the unexpected loss of Bronco's coal supply, PacifiCorp amended its contract with Bronco in March 2023 to maintain Bronco as a coal supplier to serve Hunter through December 31, 2025. The contract amendment reduced Bronco's deliveries to the Hunter Plant as follows: (2023) [redacted] tons, (2024) [redacted] tons, and (2025) [redacted] tons. Despite PacifiCorp's best efforts to maintain the Emery mine as a reliable coal supplier, Bronco continued to struggle with production and ultimately delivered only 0.51 million tons in 2023, a shortfall of [redacted] tons from the contractual tons.

Q. How have the coal supply limitations impacted the Company's dispatch of its coal generating resources?

A. As a result of the *force majeure* declarations and resulting coal delivery shortfalls in Utah, the dispatch price of the Hunter and Huntington plants was adjusted to match the coal deliveries and assure system reliability throughout 2023. In other words, the dispatch of these coal resources was adjusted to ensure the Company had sufficient coal to serve load during high-demand periods. Additionally, the dispatch price of the Jim Bridger plant was adjusted for three months in early 2023 due to delivery shortfalls at the Black Butte mine which eventually resulted in a *force majeure* declaration. Ultimately due to these issues, the Company had to reduce its overall coal generating resource output in 2023 as illustrated in Table 5 above.

Q. How has the Company amended its coal contracts for future supply?

A. In February 2024, PacifiCorp amended the Hunter and Huntington coal supply agreements with Wolverine. The amended coal supply agreement with Wolverine for the Hunter plant's fuel supply [redacted] for the Hunter plant. Beginning in [redacted], the amendment facilitates additional coal production through renewed operations at the Fossil Rock mine in Emery County, Utah. Deliveries from the Fossil Rock mine will begin in [redacted]. When fully operational, the Fossil Rock mine will provide [redacted] tons per year to the Hunter plant. The contract amendment allows the Company to direct this coal to the Huntington plant as needed.

VIII. COMPLIANCE COSTS

Q. Has there been any additional purchase requirements for NPC in 2023 for the Company to operate its system and resources?

A. Yes. The Company had to acquire allowances for the Washington Climate Commitment Act ("CCA"), which caps and reduces greenhouse gas emissions in Washington. Additionally, the Ozone Transport Rule ("OTR"), which is the federal plan for interstate transport of the 2015 ozone National Ambient Air Quality Standards was planned to become effective on August 4, 2023.

Q. Does the Company have to comply with the Washington CCA to operate its Chehalis natural gas generating plant?

A. Yes. The Washington CCA requires the Company to purchase allowances for output at its Chehalis natural gas generating facility. In 2023, the Company made $42 million in purchases, on a total-company basis, to comply with the Washington CCA. These costs were necessary to comply with applicable law for the continued operation of Chehalis, for the benefit of Utah customers, and were prudently incurred by the Company.

Q. Do these prudently incurred costs benefit Utah customers?

A. Yes. Utah customers received the benefit of the generation from the Chehalis natural gas facility which reduced NPC. NPC would have increased by $23.6 million on a total-Company basis if the generation from Chehalis were removed. Accordingly, as with other taxes and compliance costs imposed on the Company by state and federal governments, customer rates should reflect the full costs for this generation including the costs to comply with Washington CCA.

Q. Please generally describe the Ozone Transport Rule ("OTR").

A. The OTR is the Environmental Protection Agency's ("EPA") finalized federal plan for interstate transport of the 2015 ozone National Ambient Air Quality Standards, and had an effective date of August 4, 2023. The plan applied to 23 states, including Utah, and includes requirements to eliminate significant contributions of ozone or ozone precursors (specifically, nitrogen oxides ("NOx")) to nonattainment or maintenance areas in neighboring states. With respect to fossil fuel-fired electric generating units, the final rule sought to implement an allowance-based trading program where each unit was allocated a portion of the state's NOx budget during the ozone season (identified in the rule as May 1 – September 30).

Q. What is the current status of the OTR?

A. On July 27, 2023, the U.S. Tenth Circuit Court of Appeals granted petitioners', including PacifiCorp, motion to stay the EPA's final disapproval of Utah's OTR state implementation plan ("SIP") on July 27, 2023; and (2) EPA proposed approval of Wyoming's OTR SIP on August 14, 2023. While timelines cannot be predicted precisely, the OTR stay for the state of Utah is still under litigation with the U.S. Tenth Circuit Court of Appeals and is expected to remain in place at least through the 2024 ozone season. For Wyoming, the EPA published its final approval of Wyoming's interstate ozone transport plan in the Federal Register on December 19, 2023. The final approval of Wyoming's plan removes cross-state ozone transport requirements from electric generating units in the state, including PacifiCorp's generating units. As a result, Wyoming is not subject to the OTR federal implementation plan.

Q. Did the OTR impact NPC in 2023?

A. The stay was not granted until a week before the OTR was set to become effective, and the Company had to plan as if the OTR was going to be implemented for the Utah thermal generating units. Therefore the Company needed to alter its dispatch through market power purchases and its thermal generating resources as necessary to ensure there were sufficient NOx allowances to cover the generation. In 2023, the Company incurred $17 million in additional net power costs to comply with the prospective OTR requirements.

Q. Are other environmental compliance costs included in Utah customer rates?

A. Yes. All the Company's generation resources incur various types of environmental compliance costs and generation taxes, many of which are imposed by the state where the resource is located. These include costs like the Wyoming wind tax, and upgrades at generation facilities that are necessary to comply with environmental requirements like fish passage at hydroelectric plants or avian curtailments at wind facilities. These direct impacts to generation are consistently system allocated. Utah customers pay these environmental compliance and generation tax costs incurred by resources that are used to serve Utah customers.

IX. ADJUSTMENTS RELATED TO FINAL EBA RATES

Q. Please explain the adjustment to reflect the 2023 EBA Order.

A. The 2023 EBA Order adopted one adjustment to the recovery requested in that docket with respect to the Dave Johnston plant derate. The impact to this EBA is a reduction to the requested recovery by $153,260 thousand, including interest.

Q. Please explain the adjustment related to the 2022 EBA.

A. After collection of the authorized EBA in Docket No. 22-035-01 through Schedule 94 concluded, $1,073,739 still remained to be collected from customers. The Company has included this remaining balance to be recovered in this EBA.

Q. In your rebuttal testimony from the 2023 EBA, you agreed to provide certain information related to the Company's use of coal.[6] Is this information provided in this filing?

A. Yes, this information has been provided in my workpapers. Specifically, the Company has provided information on the forecasted and actual generation at each plant, coal consumed at each plant, and the price of coal at each plant.

X. IMPACT OF PARTICIPATING IN THE WEIM

Q. What is the CAISO Western Energy Imbalance Market?

A. The CAISO WEIM is an advanced real-time energy market that automatically finds low-cost energy to serve real-time consumer demand across the west by allowing participants to buy and sell power close to the time electricity is consumed. Since its launch in 2014, the WEIM has enhanced grid reliability, improved the integration of renewable resources, lowered carbon emissions, and generated significant cost savings for its participants.

Q. Are the actual benefits from participating in the WEIM included in the EBA deferral?

A. Yes. Participation in the WEIM provides significant benefits to customers in the form of reduced Actual NPC. The benefits are embedded in Actual NPC through lower fuel costs, lower purchased power costs, and higher wholesale sales revenue.

Q. What are the actual WEIM benefits included in the EBA deferral?

A. CAISO's WEIM benefits report indicates that PacifiCorp has received $154 million in

[6] *In the Matter of the Application of Rocky Mountain Power to Increase the Deferred EBA Rate through the Energy Balancing Account Mechanism*, Docket No. 23-035-01, Response Testimony of Jack Painter at 10 (Dec. 7, 2023).

benefits in 2023. Since inception of the WEIM, PacifiCorp has received $746 million in total benefits.

XI. CONCLUSION

Q. Please summarize your testimony.

A. The EBA deferral of $455.0 million, including interest for the calendar year 2023 Deferral Period was accurately calculated in compliance with the EBA tariff and previous Commission orders. The increase is driven coal supply limitations, significantly higher market prices and natural gas prices, and extreme weather events. Increased costs were partially offset by lower coal fuel expenses.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(JP-1)
Docket No. 24-035-01
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 2024

Utah Energy Balancing Account Mechanism
January 1, 2023 - December 31, 2023
Exhibit 1 - Commission Order Calculation Method (Dynamic Annual Allocation Factor

Line No.		Reference	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Total
	Actual: Utah Allocated														
1	NPC	(2.1)	$ 87,115,786	$ 94,711,550	$ 94,360,046	$ 71,381,063	$ 70,688,276	$ 78,786,766	$ 130,732,789	$ 130,908,754	$ 103,053,917	$ 77,891,882	$ 87,720,890	$ 86,865,822	$ 1,114,217,542
2	PTC	(9.1)	(11,569,395)	(11,732,402)	(10,362,476)	(9,991,141)	(6,899,143)	(6,338,308)	(5,844,549)	(6,744,425)	(6,570,404)	(6,771,680)	(11,176,561)	(10,822,828)	(104,823,313)
3	Wheeling Revenue	(4.1)	(6,709,895)	(5,688,372)	(6,302,745)	(6,283,122)	(4,106,862)	(6,459,925)	(7,512,922)	(7,707,580)	(6,662,964)	(5,966,821)	(6,223,190)	(5,257,769)	(74,882,166)
4	Total	∑ Lines 1:3	$ 68,836,497	$ 77,290,776	$ 77,694,825	$ 55,106,800	$ 59,682,270	$ 65,988,533	$ 117,375,318	$ 116,456,749	$ 89,820,549	$ 65,153,381	$ 70,321,138	$ 70,785,225	$ 934,512,062
5	Jurisdictional Sales	(5.2)	2,170,876	1,982,472	2,011,419	1,804,667	2,014,866	1,998,647	2,831,347	2,495,105	2,104,021	1,992,475	2,032,232	2,240,646	25,678,773
6	Actual Utah $/MWh	Line 4 / Line 5	**$ 31.71**	**$ 38.99**	**$ 38.63**	**$ 30.54**	**$ 29.62**	**$ 33.02**	**$ 41.46**	**$ 46.67**	**$ 42.69**	**$ 32.70**	**$ 34.60**	**$ 31.59**	**$ 36.39**
	Base: Utah Allocated														
7	NPC	(3.1)	$ 52,896,516	$ 49,963,481	$ 51,232,250	$ 45,143,308	$ 46,529,610	$ 53,485,781	$ 61,875,110	$ 58,318,910	$ 49,315,103	$ 48,730,667	$ 51,240,255	$ 55,415,210	$ 624,146,199
8	PTC	(9.1)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(106,227,616)
9	Wheeling Revenue	(4.1)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(50,632,163)
10	Total	∑ Lines 7:9	$ 39,824,867	$ 36,891,833	$ 38,160,602	$ 32,071,659	$ 33,457,962	$ 40,414,132	$ 48,803,462	$ 45,247,261	$ 36,243,454	$ 35,659,019	$ 38,168,606	$ 42,343,562	$ 467,286,420
11	Jurisdictional Sales	(5.2)	2,087,756	1,833,770	1,924,709	1,851,240	1,929,518	2,156,059	2,546,774	2,449,322	2,055,691	1,956,778	1,940,943	2,104,828	24,837,388
12	Base Utah $/MWh	Line 10 / Line 11	**$ 19.08**	**$ 20.12**	**$ 19.83**	**$ 17.32**	**$ 17.34**	**$ 18.74**	**$ 19.16**	**$ 18.47**	**$ 17.63**	**$ 18.22**	**$ 19.66**	**$ 20.12**	**$ 18.81**
	Deferral:														
13	$/MWH Differential	Line 6 - Line 12	$ 12.63	$ 18.87	$ 18.80	$ 13.21	$ 12.28	$ 14.27	$ 22.29	$ 28.20	$ 25.06	$ 14.48	$ 14.94	$ 11.47	$ 17.58
14	EBA Deferrable	Line 5 * Line 13	**$ 27,426,072**	**$ 37,407,351**	**$ 37,815,045**	**$ 23,841,992**	**$ 24,744,380**	**$ 28,524,997**	**$ 63,118,635**	**$ 70,363,733**	**$ 52,724,997**	**$ 28,843,847**	**$ 30,357,320**	**$ 25,709,374**	**$ 450,877,742**
15	Special Contract Customer Adjustment Subject to Deadband	(7.1)	(8,775,194)	(3,987,321)	(2,661,646)	(3,899,049)	434,453	(462,967)	(4,210,574)	(4,624,699)	(2,538,638)	(5,528,613)	(3,541,170)	(2,000,758)	(41,796,176)
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	(8,425,194)	(3,987,321)	(2,661,646)	(3,899,049)	434,453	(462,967)	(4,210,574)	(4,624,699)	(2,538,638)	(5,528,613)	(3,541,170)	(2,000,758)	(41,446,176)
18	Utah Situs Resource Adjustment	(8.1)	(120,302)	(51,959)	147,922	172,868	775,000	645,515	(494,836)	(291,450)	418,870	243,386	126,882	149,797	1,721,691
19	Total Incremental EBA Deferral	∑ Lines 14 and Lines 17:18	**$ 18,880,575**	**$ 33,368,071**	**$ 35,301,320**	**$ 20,115,810**	**$ 25,953,833**	**$ 28,707,545**	**$ 58,413,225**	**$ 65,447,584**	**$ 50,605,230**	**$ 23,558,619**	**$ 26,943,033**	**$ 23,858,413**	**$ 411,153,257**
	Energy Balancing Account:														
20	Monthly Interest Rate	Note 1	0.25%	0.25%	0.25%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	
21	Beginning Balance	Prior Month Line 26	$ -	$ 18,751,114	$ 52,209,250	$ 87,688,130	$ 108,176,190	$ 134,591,414	$ 164,941,976	$ 224,094,583	$ 290,520,216	$ 342,328,204	$ 367,235,383	$ 395,628,275	$ -
22	Incremental Deferral	Line 19	18,880,575	33,368,071	35,301,320	20,115,810	25,953,833	28,707,545	58,413,225	65,447,584	50,605,230	23,558,619	26,943,033	23,858,413	411,153,257
23	2022 EBA Collection True-Up	Docket 22-035-01	-	-	-	-	-	1,073,739	-	-	-	-	-	-	1,073,739
24	2023 EBA Final Order Adjustment	Docket 23-035-01	(153,260)	-	-	-	-	-	-	-	-	-	-	-	(153,260)
25	Interest	Line 20 * (Line 21 + 50% x Line 22)	23,799	90,064	177,561	372,249	461,391	569,277	739,383	978,050	1,202,759	1,348,559	1,449,859	1,552,115	8,965,067
26	**Ending Balance**	∑ Lines 21:25	**$ 18,751,114**	**$ 52,209,250**	**$ 87,688,130**	**$ 108,176,190**	**$ 134,591,414**	**$ 164,941,976**	**$ 224,094,583**	**$ 290,520,216**	**$ 342,328,204**	**$ 367,235,383**	**$ 395,628,275**	**$ 421,038,802**	**$ 421,038,802**
27	Interest Accrued January 1, 2024 through March 31, 2024	Line 26 * (1 + 1.0457% / 12) ^ 3 - Line 26													4,828,711
28	Interest Accrued April 1, 2024 through June 30, 2024	Line 26 and 27 * (1 + 1.0534% / 12) ^ 3 - Line 26 and 27													4,884,089
29	Interest Accrued through Rate Effective Period July 1, 2024 through June 30, 2026														24,201,822
30	**Requested EBA Recovery**	∑ Lines 26:29													**$ 454,953,425**

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