Rocky Mountain Power
Docket No. 23-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Jack Painter

May 2023

Q. Please state your name, business address, and present position with PacifiCorp dba 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.

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.

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, 2022, through December 31, 2022 ("Deferral Period"). More specifically, I provide the following:

- Details supporting the calculation of the Company's request to recover $175.0 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 2022 EBA,[1] and an adjustment to include the remaining uncollected balance from the 2021 EBA;[2]

- Explanation for modifications of the NPC accounting treatment of situs-assigned resources to reflect a lower of actual cost or mark-to-market calculation instead of only a mark-to-market calculation;
- Discussion of the main differences between adjusted actual net power costs ("Actual NPC") and net power costs in rates ("Base NPC");
- 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; and
- An update on the enhanced EBA documentation requested by the Division of Public Utilities.

Q. Is an additional witness presenting testimony specifically for the EBA and Electric Service Schedule No. 94 ("Schedule 94") in this case?

A. Yes. Mr. Robert M. Meredith, Director, Pricing & Tariff Policy, provides testimony on the proposed Schedule 94 rates.

Summary of the EBA Deferral Calculation

Q. Please summarize the Company's EBA application.

A. The Company's application requests recovery of $175.0 million in deferred costs,

[1] *Rocky Mountain Power's Application for Approval of the 2022 Energy Balancing Account*, Docket No. 22-035-01, Order (Jan. 9, 2023) ("2022 EBA Order").
[2] *Rocky Mountain Power's Application for Approval of the 2022 Energy Balancing Account*, Docket No. 21-035-01, Order (Feb. 23, 2022).

comprised of $220.8 million of EBA-related costs, a credit of $52.6 million for sales made to a special contract customer, a $0.5 million adjustment for Utah situs-assigned resources, a credit of $0.6 million to reflect the 2022 EBA Order, a $2.0 million adjustment to reflect the remaining balance from the 2021 EBA, and approximately $5.0 million of interest.

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:

- Modifications of the NPC accounting treatment of situs-assigned resources to reflect a lower of actual cost or mark-to-market calculation instead of only a mark-to-market calculation.
- An inclusion of two adjustments to reflect a $0.6 million reduction from the 2022 EBA and a rollover of $2.0 million in unrecovered deferred balances that were previously approved for recovery in the 2021 EBA.

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

** Calculated monthly*

The EBA deferral of $220.8 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:

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

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

[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 (December 30, 2020).

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

A. The EBA deferral calculation consists of three revenue requirement components: net power costs ("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 $2.013 billion. This amount captures all components of NPC as defined in the Company's GRC proceedings and modeled by the Company's Generation and

Regulation Initiative Decision Tool ("GRID") 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. Is the Company aware of any potential upcoming changes to the FERC accounting that would affect costs included in the EBA?

A. Yes. On July 28, 2022, the FERC issued a Notice of Proposed Rulemaking (Docket No. RM21-11-000) 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. Once the FERC's decision is final, what costs would be affected?

A. The change in accounting would affect the costs associated with greenhouse gas and environmental allowances that have been booked to FERC account 555 and historically included in the EBA in the Company's general ledger ("GL") account 546516, which

[4] *Notice of Proposed Rulemaking*, 180 FERC ¶ 61,050, Docket No. RM21-11-000 (Jul. 28, 2022) *available at* https://www.ferc.gov/media/e-3-rm21-11-000.

is currently listed in Schedule 94 as costs that are included in the EBA.

Q. Why is the Company mentioning the potential FERC accounting change at this time?

A. The Company anticipates the FERC will approve the accounting change and wanted to raise the matter to inform the Commission and the parties of the upcoming change. Once the FERC issues its final decision, the Company will file for approval to revise the FERC accounts listed in Schedule 94 accordingly, possibly in the 2024 EBA that will be filed on May 1, 2024.

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;
- Legal fees related to fines and citations included in the cost of coal;
- Adjustments related to liquidated damages that occurred outside the Deferral Period—all liquidated damage fees per a coal supply agreement are booked in accordance with generally accepted accounting principles ("GAAP").

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.

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 2023 EBA, the adjustment for sales made to a special contract customer is a $52.6 million credit.

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 eight resources or programs that are situs-assigned with four in Utah and four in Oregon. The Utah situs-assigned resources or programs are Pavant III Solar for the Utah Subscriber Solar Program, the Utah Transition Program for customer generators, Amor IX/Soda Lake Geothermal under Electric Service Schedule No. 32

("Schedule 32"), and Cove Mountain Solar 2 and Graphite 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 has the Company treated situs-assigned resources in the past?

A. The Company has used the mark-to-market calculation to determine the energy impact on NPC. Generally, the mark-to-market calculation resulted in a reduction to NPC for non-participating states with the difference between the market value and actual cost situs-assigned to the state of origin.

Q. Did the Company change the treatment for situs-assigned resources? Please explain.

A. The mark-to-market calculation has traditionally worked well in the past because situs-assigned resources have typically cost more compared to market prices. With significantly rising market prices, the mark-to-market calculation does not protect non-participating states in the same manner and only using the mark-to-market calculation could shift higher costs to non-participating states when market prices are higher than actual costs.

Q. What changes has the company made in this EBA filing for situs-assigned resources?

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 change in treatment?

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 Utah Schedule 32 and Schedule 34 are zero, there are specific program or contractual costs situs-assigned in the EBA discussed later in my testimony. Finally, the Utah Transition Program for customer generators is excluded from this treatment since the terms of a Settlement Agreement in Docket No. 14-035-114 specify the methodology for the EBA adjustment.

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, the Utah Transition Program for Customer Generators, excess generation purchases from Schedule 32 and Schedule 34 customers, the 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") Phase 3A 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 $157,149.

Q. Please describe the Utah Transition Program for Customer Generators (“Transition Program”).

A. In Docket No. 14-035-114, the Commission approved the Transition Program Electric Service Schedule No. 136, effective November 15, 2017, which measures the difference between the electricity supplied by the Company and the electricity generated by an eligible customer-generator and fed back to the electric grid at

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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).

15-minute intervals. The program enables 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.

Q. Please describe the situs-assigned adjustment to the EBA for the Transition Program.

A. Under the stipulation in Docket No. 14-035-114, the difference between export credits to eligible customers and the market value of the exports is recovered from or credited back to Utah customers through the EBA. The EBA adjustment for the Transition Program is a credit to customers of $179,212.

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 $35,226. 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 $202,492. 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 $574,675.

Differences in NPC

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 $2.013 billion, approximately $583 million more than Base NPC for the Deferral Period. Table 2 below 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	**$**	**1,431**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue		(62)
Purchased Power Expense		337
Coal Fuel Expense		(22)
Natural Gas Expense		311
Wheeling and Other Expense		18
Total Increase/(Decrease)		**583**
Adjusted Actual NPC	**$**	**2,013**

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

A. The Base NPC for the 2023 EBA was 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.

Q. Please describe some of the weather events that impacted NPC.

A. Similar to 2021, calendar year 2022 was also marked by several extreme and unforeseeable weather events that has a collective impact on Actual NPC during the year. Multiple heat waves across the Company's service territories throughout July, August, and September had a significant effect on market prices, ultimately leading to an increase in NPC. Cumulatively, the NPC differential for those months amounted to $115.7 million, which is almost half of the entire $276.9 million variance on a Utah-allocated basis.

Additionally, ongoing drought in the West, which began in the summer of 2020, continued to impact Actual NPC because it reduced the availability of the Company's hydro resources. In 2022, actual generation from hydro resources were 690,904 MWhs, or 19 percent, lower than forecasted generation and needed to be replaced to meet customer demand either through system dispatch of other resources, reduced market sales, increased market purchases, or any combination of these options. The estimated impact on total-Company NPC in 2022 due to decreased hydro MWhs from drought is $78 million.

Finally, 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. Natural gas prices across the Company's delivery points drastically increased. At the Opal natural gas trading hub, average prices were 424 percent higher in December 2022 as compared to December 2021, while market prices at the Mid-Columbia and Four-Corners trading hubs were, on average, 406 percent higher across all load hours. The NPC differential in December alone is $64.3 million, or 23 percent, of the total Utah-allocated NPC variance.

Q. How has the conflict in Ukraine impacted regional natural gas fuel prices?

A. The ongoing conflict in Ukraine has resulted in decreased availability of natural gas in Europe, which was previously sourced from Russian imports. With decreased European supply, the associated European demand has turned to U.S. domestic supply to fill the gap. This has resulted in increased competition over domestic supply, which has driven regional natural gas fuel prices upwards due to domestic production being unable to keep pace with the increased demand. This increase in natural gas fuel prices correspondingly increases regional natural gas market prices and regional power market prices, in that order. It is difficult to predict (or forecast) how long, and in what direction, these factors will continue to impact regional prices.

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 $337 million increase in purchased power expense, a $311 million increase in natural gas expense, and a $18 million increase in wheeling and other expenses, which were partially offset by a $62 million increase in wholesale sales revenue and a $22 million decrease in coal fuel expense.

Q. Please explain the changes in wholesale sales revenue.

A. Wholesale sales revenue increased relative to Base NPC mainly due to higher market prices. The average price of actual market sales transactions (represented in GRID as short-term firm and system balancing sales) was $34.27/MWh, or 107 percent, higher than the average price in Base NPC. Of the $62 million increase to wholesale sales, revenue from market transactions represents the largest change to Base NPC. Market transactions were approximately $32 million higher than Base NPC even though actual wholesale market volumes were 3,002 gigawatt-hours ("GWh"), or 45 percent, lower than the Base NPC.

Q. Please explain the changes in purchased power expense.

A. The most significant driver, expenses from market purchases (represented in GRID as short-term firm and system balancing purchases), increased by $635 million compared to Base NPC. Actual market purchases were 3,356 GWh (94 percent) higher than Base NPC, while the average price of actual market purchase transactions was $83.63/MWh, or 487 percent, higher than Base NPC. The biggest impact to market transaction prices was tied to several heat waves throughout July, August, and September, further compounded by ongoing drought dating back to the summer of 2020.

During the summer 2022 heat waves, the Mid-Columbia market hub saw an average increase in heavy load hour market prices of 103 percent, or just over double, in August and September as compared to the same timeframe in 2021. This is significant considering 2021 also experienced an extreme heat dome and drought. The Four Corners market hub saw an average increase in heavy load hour market prices of 151 percent for the same period.

Q. Please explain the changes in wheeling expenses.

A. The increase in wheeling expenses relative to Base NPC was primarily due to both an increase in short-term firm wheeling expense of $13.6 million and an increase in firm wheeling expense of $5.8 million.

Q. Please explain the changes in coal fuel expense.

A. Coal fuel expense decreased because the average cost of coal generation decreased from $21.45/MWh in Base NPC to $20.47/MWh in the Deferral Period. Even though coal generation volume increased 297 GWh (1 percent) compared to Base NPC, the lower average cost of generation results in an overall decrease of approximately $22 million in coal fuel expense.

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

A. The total natural gas fuel expense in Actual NPC increased by $311 million compared to Base NPC due to an increase in the average cost of natural gas generation from $20.73/MWh in Base NPC to $44.61/MWh (115 percent) in the Deferral Period caused by conflict in Ukraine and a historic winter weather event as discussed above. Increased costs were offset by a decrease in natural gas generation volume of 742 GWh (5 percent) below Base NPC during the Deferral Period.

Adjustments Related to Final 2022 EBA Rates

Q. Please explain the adjustment to reflect the 2022 EBA Order.

A. The 2022 EBA Order adopted three adjustments to the recovery requested in that docket: (1) $189,552 to correct a carrying charge error; (2) $785 to correct the PTC calculation with respect to net negative generation at TB Flats; and (3) the adjustment with respect to the Craig Outage. The impact to this EBA is a reduction to the requested recovery by $598 thousand, including interest.

Q. Please explain the adjustment related to the 2021 EBA.

A. In the Settlement Stipulation in Docket No. 21-035-01, the parties agreed to leave the then-current Schedule 94 rates in place as described in paragraph 10. The Settlement Stipulation specified that any difference between the Stipulated Adjustment of $6,625,339 and the actual amount collected would be accounted for when setting final rates for the 2022 EBA. The Company has included the remaining $2.0 million to be recovered in this EBA.

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 $200 million in benefits in 2022. Since inception of the WEIM, PacifiCorp has received $591.4 million in total benefits.

Enhanced Documentation for EBA Review

Q. In your surrebuttal testimony for the 2022 EBA, you responded to a request by the Division of Public Utilities ("Division") to enhance the documentation for outages at the Company's wind and hydroelectric generating assets. Can you provide the Commission with an update on the outcome of the discussions?

A. Yes. In my surrebuttal testimony, the Company committed to meet with the Division to discuss enhanced documentation for wind and hydroelectric outages. The Company and Division met and agreed that the Company will provide enhance the EBA documentation for renewable resources as follows:

- **Wind generation assets**
  - Filing Requirement 6, part c will contain additional detail to the date/time and type of event
  - Forced outage events that resulted in a loss that is greater than 3,000 MWh, a significant event report will be created by the Company that will be provided upon request through discovery

- **Hydroelectric generation assets**
    - Filing Requirement 6, part c will contain additional detail for forced outage events greater than 72 hours

The Company is in the process of implementing the enhanced documentation, so it will be available with the 2024 EBA. The Division has indicated that it may request further revisions to the required documentation in the future if needed. The Company appreciates the constructive discussions with the Division and looks forward to a continued discussion on providing the information needed to support the Division's review of the EBA filings.

Q. The 2022 EBA Order also mentioned that the Company agreed to provide certain additional detail in its annual EBA filings with respect to the calculation of the PTCs. Was this provided?

A. Yes. The requested information is provided with the filing in the Filing Requirement 6 as new subpart o.

Conclusion

Q. Please summarize your testimony.

A. The EBA deferral of $175.0 million, including interest for the calendar year 2022 Deferral Period was accurately calculated in compliance with the EBA tariff and previous Commission orders. The increase is driven by extreme weather events, increased market purchases, and both higher market prices and natural gas fuel prices. These increased costs were offset by lower coal fuel expenses and an increase in wholesale sales revenue.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(JP-1)
Docket No. 23-035-01
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 2023

Utah Energy Balancing Account Mechanism
January 1, 2022 - December 31, 2022
Exhibit 1 - Commission Order Calculation Method (Dynamic Annual Allocation Factor)

Line No.		Reference	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Total
	Actual: Utah Allocated														
1	NPC	(2.1)	$ 65,857,447	$ 56,601,282	$ 54,554,397	$ 58,892,441	$ 61,885,767	$ 59,734,148	$ 101,879,231	$ 96,874,718	$ 86,442,405	$ 62,109,318	$ 76,513,531	$ 119,710,454	$ 901,055,139
2	PTC	(9.1)	(12,983,850)	(12,567,344)	(11,014,345)	(11,368,691)	(9,569,395)	(6,922,467)	(5,450,761)	(4,966,781)	(5,725,993)	(7,282,697)	(9,640,650)	(13,472,285)	(110,965,259)
3	Wheeling Revenue	(4.1)	(5,475,125)	(5,407,112)	(5,516,236)	(6,074,775)	(8,241,758)	(8,148,751)	(8,506,561)	(8,043,440)	(10,808,377)	(6,031,832)	(5,736,659)	(6,351,573)	(84,342,200)
4	Total	∑ Lines 1:3	$ 47,398,472	$ 38,626,826	$ 38,023,816	$ 41,448,975	$ 44,074,613	$ 44,662,930	$ 87,921,909	$ 83,864,497	$ 69,908,035	$ 48,794,790	$ 61,136,222	$ 99,886,596	$ 705,747,680
5	Jurisdictional Sales	(5.2)	2,120,291	1,879,963	1,985,772	1,799,694	1,957,786	2,244,379	2,800,853	2,544,063	2,172,942	1,936,152	2,077,699	2,237,292	25,756,887
6	Actual Utah $/MWh	Line 4 / Line 5	**$ 22.35**	**$ 20.55**	**$ 19.15**	**$ 23.03**	**$ 22.51**	**$ 19.90**	**$ 31.39**	**$ 32.96**	**$ 32.17**	**$ 25.20**	**$ 29.42**	**$ 44.65**	**$ 27.40**
	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	$ 3.28	$ 0.43	$ (0.68)	$ 5.71	$ 5.17	$ 1.16	$ 12.23	$ 14.49	$ 14.54	$ 6.98	$ 9.76	$ 24.53	$ 8.59
14	EBA Deferrable	Line 5 * Line 13	**$ 6,952,987**	**$ 805,671**	**$ (1,347,470)**	**$ 10,270,329**	**$ 10,126,480**	**$ 2,593,286**	**$ 34,249,564**	**$ 36,867,062**	**$ 31,597,345**	**$ 13,511,654**	**$ 20,278,309**	**$ 54,878,200**	**$ 220,783,416**
15	Special Contract Customer Adjustment Subject to Deadband	(7.1)	(1,103,232)	(797,887)	(580,698)	(3,771,706)	(1,297,768)	214,312	(2,370,023)	(5,715,089)	(10,250,603)	(3,397,715)	(5,213,041)	(18,675,152)	(52,958,601)
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	(753,232)	(797,887)	(580,698)	(3,771,706)	(1,297,768)	214,312	(2,370,023)	(5,715,089)	(10,250,603)	(3,397,715)	(5,213,041)	(18,675,152)	(52,608,601)
18	Utah Situs Resource Adjustment	(8.1)	187,002	321,549	508,126	430,924	260,947	163,163	(61,484)	(243,856)	(1,233,257)	285,917	62,505	(205,501)	476,032
19	Total Incremental EBA Deferral	∑ Lines 14 and Lines 17:18	**$ 6,386,757**	**$ 329,332**	**$ (1,420,042)**	**$ 6,929,547**	**$ 9,089,659**	**$ 2,970,760**	**$ 31,818,057**	**$ 30,908,117**	**$ 20,113,484**	**$ 10,399,856**	**$ 15,127,773**	**$ 35,997,547**	**$ 168,650,846**
	Energy Balancing Account:														
20	Monthly Interest Rate	Note 1	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	
21	Beginning Balance	Prior Month Line 26	$ -	$ 5,797,052	$ 6,141,487	$ 4,735,205	$ 11,685,593	$ 22,787,218	$ 25,819,672	$ 57,743,789	$ 88,837,950	$ 109,202,792	$ 119,893,421	$ 135,345,148	$ -
22	Incremental Deferral	Line 19	6,386,757	329,332	(1,420,042)	6,929,547	9,089,659	2,970,760	31,818,057	30,908,117	20,113,484	10,399,856	15,127,773	35,997,547	168,650,846
23	2021 EBA Collection True-Up	Docket 21-035-01	-	-	-	-	1,970,714	-	-	-	-	-	-	-	1,970,714
24	2022 EBA Final Order Adjustment	Docket 22-035-01	(597,795)	-	-	-	-	-	-	-	-	-	-	-	(597,795)
25	Interest	Line 20 * (Line 21 + 50% x Line 22)	8,090	15,103	13,760	20,842	41,252	61,693	106,060	186,045	251,357	290,774	323,954	389,749	1,708,678
26	**Ending Balance**	∑ Lines 21:25	**$ 5,797,052**	**$ 6,141,487**	**$ 4,735,205**	**$ 11,685,593**	**$ 22,787,218**	**$ 25,819,672**	**$ 57,743,789**	**$ 88,837,950**	**$ 109,202,792**	**$ 119,893,421**	**$ 135,345,148**	**$ 171,732,444**	**$ 171,732,444**
27	Interest Accrued January 1, 2023 through March 31, 2023	Line 26 * (1 + 1.0305% / 12) ^ 3 - Line 26													1,312,791
28	Interest Accrued April 1, 2023 through June 30, 2023	Line 26 and 27 * (1 + 1.0457% / 12) ^ 3 - Line 26 and 27													1,984,581
29	**Requested EBA Recovery**	∑ Lines 26:28													**$ 175,029,815**

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