Rocky Mountain Power
Docket No. 21-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Jack Painter

March 2021

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.

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. No.

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, 2020 through December 31, 2020 ("Deferral Period"). More specifically, I provide the following:

- Details supporting the calculation of the Company's request to recover $1.7 million for excess EBA-related costs, including interest, an adjustment for sales made to a special contract customer, and Utah situs resource adjustments included in the EBA for the true-up of solar facilities and the Utah Transition

Program for Customer Generators;

- 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 energy imbalance market (“EIM”) with California Independent System Operator (“CAISO”) and the benefits from EIM that are passed through to customers.

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 and Cost of Service, 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 $1.7 million in deferred costs, comprised of $6.7 million of an EBA-related refund to customers, a cost of $5.0 million for sales made to a special contract customer, a $3.2 million adjustment for Utah situs resources, and approximately $245 thousand of interest.

Q. Are there any changes to the EBA calculation?

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

- An adjustment related to Electric Service Schedule No. 34 (“Schedule 34”) contract costs associated with the contract approved by the Utah Public Service Commission (“Commission”) in Docket No. 16-035-27.
- The Deer Creek Postretirement Benefits Other than Pension (“PBOP”)

adjustment included in previous EBA filings is not included in this filing because the savings from the PBOP regulatory liability balance was used to offset the remaining unrecovered Deer Creek balances as authorized in Docket No. 20-035-04.

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 2020 EBA Deferral			*Exhibit RMP___(JP-1) Reference*
Actual EBA ($/MWh)	$	25.01	*Line 5*
Base EBA ($/MWh)		25.25	*Line 10*
$/MWh Differential	**$**	**(0.24)**	
Utah Sales (MWh)		24,869,997	*Line 4*
EBA Deferrable*	$	(6,713,705)	*Line 12*
Special Contract Customer Adjustment*		5,010,211	*Line 15*
Utah Situs Resource Adjustment*		3,174,121	*Line 16*
Total Deferrable	$	1,470,627	*Line 17*
Interest Accrued through December 31, 2020		182,131	*Line 21*
Interest Accrued January 1, 2021 through March 31, 2021		16,084	*Line 23*
Interest Accrued April 1, 2021 through February 28, 2022		47,099	*Line 24*
Requested EBA Recovery	**$**	**1,715,940**	*Line 25*

** Calculated monthly*

The EBA deferral of $6.7 million is calculated as the difference between the Actual NPC and wheeling revenue and the Base NPC and wheeling revenue, as established in the 2014 General Rate Case ("GRC"). The calculation of the monthly amount debited or credited into the EBA Deferral Account is based on the following formula:

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

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

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

A. The EBA deferral calculation consists of two revenue requirement components: NPC and wheeling revenue. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses, and wheeling expenses, less wholesale sales revenue. Wheeling revenue includes amounts booked to FERC account 456.1 and revenues from transmission of electricity of others. Collectively, these two 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 $1.503 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. 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;
- Situs assignment of the generation from Oregon solar resources procured to satisfy Oregon Revised Statute 757.370 solar capacity standard;

- Situs assignment of Oregon allocated excess amortization related to a prepaid wheeling expense;
- Situs assignment of certain Utah resources;
- 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");
- Electric Service Schedule No. 32 ("Schedule 32") and Schedule 34 contracts; and
- An adjustment for reclassification of wholesale sales revenue above the FERC price cap. Sales pending refund are accounted for in FERC Account 449, a non-regulatory NPC account instead of FERC Account 447. Because this transaction is recorded in a non-NPC account and the wholesale sales revenue is recorded in FERC Account 447, the adjustment should be included in the 2021 EBA to align the pending refund with the matching sales revenue in accordance with 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 settlement stipulation in the 2014 GRC set the Base NPC effective

September 1, 2014 using the Commission Order Method, which was originally approved by the Commission in Docket No. 09-035-15. The Base NPC and Commission Order Method were detailed in Exhibit A of the stipulation in the 2014 GRC. 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 interest 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 2021 EBA, the adjustment for sales made to a special contract customer is a $5.0 million expense.

Q. Please describe the Utah Situs Resource Adjustment.

A. The Utah Situs Resource Adjustment accounts for the Utah situs costs of certain resources, namely the Utah Subscriber Solar Program and the Utah Transition Program for Customer Generators.

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 EBA adjustment rate schedule changes (Schedule 73, Special Condition 15).

Q. Please describe the 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.[1] 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 approximately $83 thousand.

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 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 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

[1] Order approving amended settlement agreement, Docket No. 15-035-61, issued October 21, 2015, Page 7 of the amended settlement stipulation.

Program is approximately $3.2 million.

Q. Please describe the adjustment to the EBA for the Schedule 32 Contract.

A. Schedule 32 is a unique retail service option 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 ("PPA") 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 ("Schedule 37") avoided costs rates.

Q. Please describe the adjustment to the EBA for the Schedule 34 Contract.

A. Schedule 34 is also a unique retail service option 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. PPA costs and generation from renewable energy facilities for the customer are removed from NPC in the EBA and any excess generation is purchased at Schedule 37 avoided costs rates.

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 $1.503 billion, approximately $12 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	**$ 1,491**
Increase/(Decrease) to NPC:	
Wholesale Sales Revenue	218
Purchased Power Expense	26
Coal Fuel Expense	(212)
Natural Gas Expense	(16)
Wheeling and Other Expense	(8)
Total Increase/(Decrease)	**9**
2014 GRC Settlement Adjustment	3
Total Company NPC Difference	**$ 12**
Adjusted Actual NPC	**$ 1,503**

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

A. The Base NPC for the 2021 EBA was set in the 2014 GRC and became effective September 1, 2015. Base NPC used a test period of 12 months from July 2014 through June 2015 and set total-company Base NPC at $1.491 billion.

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 $218 million reduction in wholesale sales, and a $26 million increase in purchased power expense. The items were partially offset by a $16 million decrease in natural gas expense, a $212 million reduction in coal fuel expense, and an $8 million reduction in wheeling and other expenses.

Q. Please explain the changes in wholesale sales revenue.

A. The decline in wholesale sales revenues relative to Base NPC was a combination of lower market prices, a reduction in the wholesale sales volumes of market transactions (represented in GRID as short-term firm and system balancing sales), and expired contracts.

Revenue from market transactions is approximately $218 million lower than Base NPC due to lower market prices and lower volume of market sales transactions. The average price of actual market sales transactions was $4.81/MWh, or 12 percent, lower than the average price in Base NPC. Actual wholesale market volumes were 4,900 gigawatt-hours ("GWh"), or 50 percent, lower than the Base NPC.

Q. Please explain the changes in purchased power expense.

A. Since the 2014 GRC that set Base NPC there have been multiple changes to the Company's long-term purchased power expense including the addition of 18 new large qualifying facility contracts, and the expiration of the Hermiston PPA and the Georgia-Pacific Camas contract. The Hermiston PPA and the Georgia-Pacific Camas contract expirations resulted in lower purchased power costs of $91.3 million.

Expenses from market transactions (represented in GRID as short-term firm and system balancing purchases) decreased by $5.1 million compared to Base NPC. Actual market purchases were 1,120 GWh (23 percent) lower than Base NPC and the average price of actual market purchases transactions was $7.53/MWh (25 percent) higher than Base NPC.

Q. Please explain the changes in wheeling expenses.

A. Actual long-term wheeling expense decreased by approximately $18.6 million when compared to Base NPC due to expired wheeling contracts. This was partially offset by an increase of $12.0 million of short-term wheeling expenses.

Q. Please discuss the changes in coal fuel expense.

A. The principal driver of the coal fuel expense decrease is a coal generation volume reduction of 12,007 GWh (28 percent) compared to Base NPC. The average cost of coal generation increased slightly from $19.77/MWh in Base NPC to $20.62/MWh in the Deferral Period, but the lower generation results in an overall decrease of approximately $212 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 decreased by $16 million compared to Base NPC. The main driver of the increase is the average cost of natural gas generation decreased from $39.73/MWh in Base NPC to $21.85/MWh (45 percent) in the Deferral Period, but reduced costs were offset by an increase in natural gas generation volume of 5,013 GWh (71 percent) above Base NPC during the Deferral Period.

IMPACT OF PARTICIPATING IN THE EIM

Q. Are the actual benefits from participating in the EIM with CAISO included in the EBA deferral?

A. Yes. Participation in the EIM provides benefits to customers in the form of reduced Actual NPC. The EIM benefits are embedded in Actual NPC through lower fuel and purchased power costs. The Company is able to calculate the margin realized on its EIM imports and exports, the inter-regional benefit. The Company's EIM inter-regional benefit for the deferral period was approximately $46.8 million.

Q. How does the Company calculate its actual EIM benefits?

A. Using actual information from the EIM, including five- and 15-minute pricing, the Company identifies the incremental resource that could have facilitated the transfer to an adjacent EIM area or the CAISO in each five-minute interval. The benefit is then calculated as the difference between the revenue received less the expense of generation assumed to supply the transfer. In the event of an import, the benefit is equal to the cost of the import minus the avoided expense of the generation that would have otherwise been dispatched.

Q. Does this conclude your direct testimony?

A. Yes.