–BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH–

IN THE MATTER OF ROCKY MOUNTAIN POWER'S APPLICATION FOR APPROVAL OF THE 2024 ENERGY BALANCING ACCOUNT.	))))))))	**DOCKET NO. 24-035-01** **Exhibit No. DPU 1.0 R** **Rebuttal Testimony**

Redacted

FOR THE DIVISION OF PUBLIC UTILITIES

DEPARTMENT OF COMMERCE

STATE OF UTAH

Rebuttal Testimony of

Gary Smith

January 7, 2025

INTRODUCTION

Q. PLEASE STATE YOUR NAME, EMPLOYER, AND BUSINESS ADDRESS.

A. My name is Gary Smith. I am employed by the Division of Public Utilities (Division or DPU), State of Utah. My business address is 160 East 300 South, Salt Lake City, UT 84114.

Q. ARE YOU THE GARY SMITH WHO PREFILED DIRECT TESTIMONY FOR THE DIVISION IN THIS PROCEEDING?

A. Yes.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Division.

SUMMARY

Q. PLEASE SUMMARIZE THE PURPOSE OF YOUR REBUTTAL TESTIMONY.

A. The purpose of my rebuttal testimony is to reaffirm and clarify the Division's recommendations presented in my direct testimony after review of the testimony offered by parties in this matter, including the response testimony of Company witnesses Michael G. Wilding and Jack Painter. I also present the Division's total revised recommended adjustment removing the October 11, 2023, Naughton 2 outage totaling $185,808 detailed in the rebuttal testimony of Division witnesses Philip DiDomenico and Dan F. Koehler.

RESPONSE

Q. COMPANY WITNESS, JACK PAINTER, CLAIMS IN HIS RESPONSE TESTIMONY THAT THE COMPANY SHOULD BE ALLOWED TO RECOVER $4.7 MILLION IN SCHEDULE 137 COSTS IT DID NOT INCLUDE IN ITS DEFERRAL YEARS 2020, 2021, AND 2022 ANNUAL EBA FILINGS. HAS THE COMPANY EVER BEEN GRANTED EBA RECOVERY FOR COSTS IT FAILED TO REQUEST IN A PRIOR PERIOD?

A. No, the Division is not aware of any prior request by the Company to recover known costs it simply failed to include in the correct prior EBA deferral filing year over multiple years.

Q. MR. PAINTER CLAIMS THAT IT IS COMMON PRACTICE FOR THE COMPANY TO INCLUDE OUT OF PERIOD ADJUSTMENTS IN ITS EBA REQUESTS FOR RECOVERY. IS THE COMPANY'S REQUEST TO RECOVER THE $4.7 MILLION SCHEDULE 137 COSTS DIFFERENT THAN THE EXAMPLES OF ADJUSTMENTS PROVIDED BY MR. PAINTER?

A. Yes, the prior period schedule 137 cost adjustment the Company is seeking is different from the expected annual true-up adjustment of the variance between actual customer collections and the Commission ordered EBA collection; it is also different than the liquidated damage payments received in the deferral year for prior year's nonperformance of wind assets mentioned by Mr. Painter.[1] The requested prior period schedule 137 cost adjustment is not a "common" adjustment. It is the result of the Company's failure to include them in the proper filing year and not due to any expected true up or lag in the timing of when costs are known or when

[1] Response Testimony of Jack Painter at 4:83-5:92.

payments are received. Other examples have not been oversights of this type. Failure of the Company to include its known costs in prior EBA filings is insufficient justification for cost recovery in periods for which rates have already been finalized and approved. This request dating back three EBA deferral periods is concerning. Without some finality to rates the Company could request adjustments for any additional oversights dating as far back as October 2011.[2] The Division questions whether the Company would agree to grant other parties the same opportunity to propose prior period adjusting entries that those parties simply did not notice in previous cases.

Q. MR. PAINTER REFERENCES THE FEBRUARY 16, 2017, ORDER IN DOCKET NO. 09-035-15 IN HIS RESPONSE, WHAT CLARIFICATIONS DOES THE DIVISION HAVE?

A. Mr. Painter included the following statement in his response referring to the Commission's February 16, 2017, order related to prior period adjustments:

> Furthermore, the Commission held that not allowing prior period adjustments would "disallow prudent NPC amounts booked in accordance with generally accepted accounting principles."[3]

The above statement is Mr. Painter's interpretation of an extracted portion of the order that more fully reads:

> Furthermore, PacifiCorp states Utah Code Ann. § 54-7-13.5(2)(c)(ii)32 provides for reconciliation of EBA accounts and does not preclude updates when new information becomes available.
>
> *According to PacifiCorp*, the DPU's proposal would *disallow prudent NPC amounts booked in accordance with generally accepted*

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[2] In the Matter of Rocky Mountain Power's Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism, Docket No. 09-035-15, Direct Testimony of David Thomson at 4:81-5:91 and 5:109-6:114 (Sep. 28, 2016).

[3] Response Testimony of Jack Painter at 4:76-82.

> *accounting principles* and cites examples where estimated or accrued costs or benefits from prior periods could not be reconciled with actual costs or benefits until after an audit or until more accurate information became available.
>
> We decline to accept the DPU's recommendation on this issue. We conclude that Utah Code Ann. § 54-7-13.5 permits the accounting treatment we approved previously for the EBA pursuant to this section. Further, consistent with our experience with other balancing accounts, we find that difficulties exist with closing various transactions within the deferral period. We anticipate further review and evaluation of this issue and its materiality at the conclusion of the EBA pilot period.[4]

When the Commission stated that “difficulties exist with closing various transactions within the deferral period” it appears that the Commission was quoting the Company’s view and focused on specific examples of accounting transactions that the EBA would normally encounter, like the annual true ups of the Company’s EBA filings that Mr. Painter refers to.[5] In fact, the Commission addressed the lack of ability to reconcile amounts without additional information. That case was quite different from this one. Here, the Company presents no facts involving a lack of information at the original time of filing that required. Rather than applying new, final knowledge to past years’ numbers, the Company simply discovered its own oversight and seeks now to reopen past years to include previously known costs from those years.

Q. MR. WILDING CLAIMS THAT THE DIVISION SHOULD MORE APPROPRIATELY ADDRESS THE ACQUSITION OF SUFFICIENT RESOURCES IN A DIFFERENT DOCKET. DOES THE DIVISION AGREE?

[4] In the Matter of Rocky Mountain Power’s Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism, Docket No. 09-035-15, Order at 14-15 (Feb. 16, 2017).
[5] Response Testimony of Jack Painter at 4:84-5:93.

A. In a sense, perhaps. But NPC is almost entirely the result of Company's past acquisition decisions; it always will be. Adjustments cannot be made in an Integrated Resource Plan (IRP) docket. And general rate cases do not always include estimates of costs resulting from Company policies and practices, which change from time to time. It is not clear where and how the Company believes a utility should be accountable when it fails to plan properly leading to increased costs for customers. The Company would seemingly have the Division, other parties, and the Commission, evaluate only what it does with the position in which it now finds itself, while ignoring why it now finds itself with insufficient reliable resources to meet system needs. The Division of course cannot identify a hypothetical resource that wasn't built because the Company did not consider it. The Division has raised concerns in IRP dockets as suggested by Mr. Wilding[6], but these have been largely ignored by the Company. The Division voiced concerns over the Company's failure to model natural gas generators.[7] In fact, the Company even performed a modeling run showing that the inclusion of new proxy gas generation would reduce system costs.[8] Perhaps natural gas resources from that IRP would not yet be in service, but there is no way to know that. The Company has the burden to prove its decisions are

[6] Wilding Response Test. at 19:365:378.

[7] In his Direct Testimony, Division witness David Williams noted that "in the 2021 IRP, the Division requested that the Company run a sensitivity where new natural gas plants were allowed. This resulted in the S-04 sensitivity, described in '2021 IRP – Supplemental Sensitivity Modeling Results' which was filed on the RMP website." Williams Direct Test. at 25:564-67. The sensitivity is available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/PacifiCorp_2021_IRP_Sensitivity_Cases.pdf (p. 5).

[8] Williams Direct Test. at 25:567-68: "That sensitivity showed a benefit of $159 million as compared to P02-MM CETA, which was the preferred portfolio."

prudent. Answering this question involves more than merely reviewing the Company's present condition.

Q. MR. WILDING CLAIMS THAT MARKET PURCHASE ACTIVITY TAKES PLACE IN THE WEST BECAUSE THESE POINTS OF DELIVERY HAVE HISTORICALLY EXHIBITED GREATER LIQUIDITY. DOES MR. WILDING DISCUSS OR COMPARE PRICING AT ANY AVAILABLE POINT OF DELIVERY?

A. No. Although the Division appreciates Mr. Wilding's limited comparative analysis of liquidity at select points of delivery in the east and west balancing authorities, he does not offer any similar analysis on pricing. Even if liquidity is relevant, it does not answer broader questions, such as whether the Company can effectively move resources across its territory in ways that serve Utah.

Q. HAS THE DIVISION REVIEWED MR. WILIDING'S CONFIDENTIAL WORKPAPER DATA AND COMPARED HISTORICAL PRICING AT MID-C AND PALO VERDE?

A. Yes. The Division took the historical data from Mr. Wilding's response testimony workpapers and ran comparative analyses on hourly pricing for the calendar years 2019 through 2023 and actual trades for calendar years 2018 through 2023. Understandably, the results contain a large amount of data, so DPU TABLE 1 and DPU TABLE 2 provide a summary view. Full details are included as DPU Exhibit 1.1 R.

In DPU TABLE 1, hourly pricing for Mid-C was summed up on an annual basis and compared with an annual summation of hourly pricing at Palo Verde. The Division noted that hourly pricing at Palo Verde was overall lower than at Mid-C. The Division noted that in the third quarter of each year, hourly pricing at Palo Verde commonly exceeded Mid-C (Not shown on this chart, but available in DPU Exhibit 1.1 R). Hourly pricing overall decreased during the EBA deferral year 2023.

TABLE 1

MID-C vs. Palo Verde Hourly Pricing

	MID-C Hourly Pricing $/MWh		Palo Verde Hourly Pricing $/MWh	
2019	$ 310,322.65		$ 286,941.64	
2020	$ 269,363.83	**-15.21%**	$ 279,383.49	**-2.71%**
2021	$ 446,807.86	**39.71%**	$ 424,249.52	**34.15%**
2022	$ 724,046.59	**38.29%**	$ 726,723.78	**41.62%**
2023	$ 541,816.20	**-33.63%**	$ 505,325.28	**-43.81%**

In DPU TABLE 2, the weighted average price of actual trades occurring at Mid-C was compared to the weighted average price of trades at Palo Verde for calendar years 2018 through 2023. The Division noted that the weighted average price for trades transacted at Mid-C was generally lower than those at Palo Verde until the deferral year 2023. The calendar year 2023 saw decreases in weighted average price at Palo Verde that averaged over 30% from 2022. Mid-C saw a much lower decrease averaging 4% in 2023.[9]

[9] Of course, constructing comparative prices for the times of each of the Company's Mid-C transactions would be much more involved than my analysis here. But this is the sort of analysis that should be expected from the Company. It has not, across multiple dockets, provided sufficient information to evaluate whether different procurement strategies might have proven more or less expensive than the program it has undertaken.

TABLE 2

MID-C vs. Palo Verde Day Ahead Pricing

	MID- C PEAK Wtd avg price $/MWh			Palo Verde PEAK Wtd avg price $/MWh	
2018	$ 9,205.30		$ 10,449.91	
2019	$ 9,502.94	**3.13%**	$ 8,059.74	**-29.66%**
2020	$ 6,214.67	**-52.91%**	$ 11,876.70	**32.14%**
2021	$ 14,718.11	**57.78%**	$ 15,402.31	**22.89%**
2022	$ 22,271.07	**33.91%**	$ 23,474.68	**34.39%**
2023	$ 21,268.11	**-4.72%**	$ 17,630.90	**-33.15%**

Q. DOES THE DIVISION HAVE ANY REVISIONS TO ITS RECOMMENDED WEST TRADE ADJUSTMENT RELATED TO ITS HEDGING ACTIVITIES?

A. Yes. As detailed in the Division's surrebuttal testimony of Trevor Jones filed in Docket 24-035-04, the Division recommends reducing the allocation of hedging costs to Utah from 44% to 20% rather than removing the cost of the hedges occurring in PAC West.[10] This revised allocated amount was then further reduced by the Company's hedging sales. These changes reduced the Division proposed adjustment from $129.8 million to $72.3 million as shown in DPU TABLE 3.

[10] 24-035-04, In the Matter of the Application of Rocky Mountain Power for the Authority to Increase its Retail Electric Service Rates in Utah and for Approval of it proposed Electric Service Schedules and Electric Service Regulations, Trevor Jones Surrebuttal Test. at 13:311-315.

DPU TABLE 3

[redacted]

CONCLUSION

Q. CAN THE DIVISION PROVIDE ITS TOTAL REVISED RECOMMENDED ADJUSTMENT?

A. Yes. As explained in the rebuttal testimony of Division witnesses Philip DiDomenico and Dan F. Koehler, Daymark revised its recommended adjustment, removing the October 11, 2023, Naughton 2 outage totaling $185,808, including interest. In addition, the Division reduced its recommended West Trade Adjustment from $129.8

million to $72.3 as detailed in my testimony above. The Division now recommends a revised $97.1 million reduction from the approved interim rate amount, resulting in a recommended revised adjusted total recovery of $334.5 million as follows:

May 2024 Requested Deferral (all numbers Utah allocated)	**$454,953,425**
2023 Accrued Interest Correction Adjustment	$826,579
Removal of Forecast Interest - July 2024 - June 2026	($24,201,822)
Interim Ordered Recovery (subject to adjustment and true-up)	$431,578,182
REVISED - Total Outage Adjustment	***(604,448)***
REVISED - Total Outage Adjustment - Accrued Interest	***(24,514)***
Total WA CCA Adjustment	($18,482,085)
Total WA CCA Adjustment - Accrued Interest	($931,275)
Total Sch 137 Prior Period Adjustment	($4,703,793)
Total Sch 137 Prior Period Adjustment - Accrued Interest	($126,926)
REVISED - Total West Trade Adjustment	***($72,250,029)***
REVISED - Net Adjustment (Post Interim Rate)	***($97,123,070)***
REVISED - Net Adjusted DPU Total Recommended Recovery	***$334,455,112***

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.