BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER TO INCREASE CURRENT RATES BY \$50.3 MILLION TO RECOVER DEFERRED NET POWER COSTS PURSUANT TO TARIFF SCHEDULE 95 ENERGY COST ADJUSTMENT MECHANISM AND TO DECREASE CURRENT RATES BY \$1.5 MILLION PURSUANT TO TARIFF SCHEDULE 93, REC AND SO2 REVENUE ADJUSTMENT MECHANISM	**DOCKET NO. 20000-642-EM-23** **(Record No. 17279)**

NON-CONFIDENTIAL DIRECT TESTIMONY

AND EXHIBITS

OF

BRADLEY G. MULLINS

On Behalf of

Wyoming Industrial Energy Consumers

September 8, 2023

WIEC Exhibit No. 200

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I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins. My business address is Tietotie 2, Suite 208, Oulunsalo, FI-90440 Finland.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Principal Consultant for MW Analytics, an independent consulting firm representing utility ratepayers before state public utility commissions in the Western United States.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Wyoming Industrial Energy Consumers ("WIEC"), an unincorporated trade association whose members are large energy users located in Wyoming, including ratepayers receiving electrical services from Rocky Mountain Power ("RMP" or the "Company").

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS.

A. I have been performing independent energy and utilities consulting services for over 10 years. I have sponsored expert witness testimony in over 100 regulatory proceedings on a variety of subject matters, including revenue requirements, regulatory accounting, rate development, and new resource additions. I have a Master of Accounting degree from the University of Utah. A qualification statement and a list of recent regulatory appearances can be found in **WIEC Exhibit No. 200.1**.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I discuss my review of RMP's 2023 Energy Cost Adjustment Mechanism ("ECAM") filing, including RMP's request to recover $74,027,280 in deferred net power costs ("NPC") incurred over the 12 months ending December 31, 2022 ("Deferral Period"). Specifically, I evaluate the drivers of the deferred NPC at issue; discuss an error related to the allocation of Energy Imbalance Market ("EIM") Settlements; review RMP's hedging practices in the Deferral Period; and, review the performance of RMP's wind resources in the Deferral Period.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. As detailed in **WIEC Exhibit 200.2**, I recommend the Commission reduce RMP's requested ECAM recovery by $20,692,021. Details supporting my recommendation are summarized in **Table BGM-1**, below, followed by brief descriptions of my specific adjustments.

Table BGM-1
<u>WIEC Proposed ECAM Balance Adjustments $</u>

RMP Initial Filing	**74,027,280**
Adjustments:	
EIM Settlement Allocation	(4,344,168)
2022 ECAM EIM Settlement Allocation	(1,973,714)
Gas Hedging: Westside Gas Plants	(5,629,525)
Gas Hedging: April - June Requirements	(1,031,874)
Wind Underperformance Reserve	(7,712,741)
Total Adjustments	**(20,692,021)**
Adjusted Balance	**53,335,259**

Specifically, I recommend the Commission:

1. Reduce ECAM recovery by $4,344,168 to correct the allocation of Energy Imbalance Market ("EIM") settlements, which should be based

on the System Energy ("SE") factor, consistent with the method approved for Base NPC in Docket No. 20000-578-ER-20;

2. Approve a $1,973,714 correction to the 2022 ECAM balance to reflect the proper allocation of EIM settlements following the July 1, 2022 rate effective date in Docket No. 20000-578-ER-20;

3. Disallow $5,629,525 in ECAM recovery due to RMP's failure to adequately hedge gas plant requirements in the Northwest;

4. Disallow $1,031,874 in ECAM recovery due to RMP's failure to adequately hedge gas plant requirements in the months of April through June of the Deferral Period;

5. Require RMP to remove $7,712,741 in ECAM recovery resulting from underperformance of its Energy Vision ("EV") 2020 and Repowered wind facilities and hold the balance in reserve to be collected in a future ECAM when the facilities overperform relative to their P50 production estimates.

II. BACKGROUND

Q. PLEASE PROVIDE A SUMMARY OF THE ECAM?

A. The annual ECAM filings establish the Deferred ECAM Rates in Rate Schedule 95, Energy Cost Adjustment Mechanism. The purpose of the Deferred ECAM Rate is to provide RMP with additional revenue recovery, or ratepayers with a refund, depending on whether actual ECAM costs are higher or lower than the Base ECAM costs approved in a general rate case. The ECAM is subject to an 80/20 sharing band, meaning that 80% of the variances between Forecast Base ECAM Costs and Adjusted Actual ECAM Costs are included in the Deferred ECAM Rate.

Q. WHAT COSTS ARE CONSIDERED IN THE ECAM?

A. The principal costs included in the ECAM are NPC. NPC represents the variable energy costs associated with providing electric services. It includes the cost of fuel (both coal and gas), the cost of purchased power, and the cost of wheeling (*i.e.* the cost of transmitting electricity on other utilities' transmission systems). It also includes the revenues associated with power sales in wholesale markets, including long-term power sales agreements and short-term sales in regional markets. The *net* in NPC, therefore, is representative of the fact that it includes wholesale sales transactions that offset the variable energy costs of serving retail customers. The specific FERC Accounts included in NPC include the following:

- Account 447 – Sales for Resale;
- Account 501 – Fuel (for Steam Power);
- Account 503 – Steam from Other Sources (Geothermal);
- Account 547 – Fuel (for Mechanical Power);
- Account 555 – Purchased Power; and
- Account 565 – Wheeling.[1]

In addition to these NPC FERC accounts, however, the ECAM also explicitly includes several other categories of costs, including chemical costs, coal start-up fuel costs, and production tax credits ("PTCs").

Q. ARE ALL OF THE ECAM COSTS SUBJECT TO THE 80% SHARING BAND?

A. No. Pursuant to the Commission's Order in RMP's 2020 general rate case ("GRC"), PTCs are not subject to the 80% sharing band.[2] Further, certain other

[1] Uniform System of Accounts Prescribed For Public Utilities And Licensees Subject to The Provisions of The Federal Power Act, 18 CFR 101.

[2] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $7.1 Million Per Year or 1.1 Percent, to Revise the Energy Cost Adjustment Mechanism, and to Discontinue Operations at Cholla Unit 4*, Docket No. 20000-578-ER-20 (Record No. 15464), Memorandum Opinion, Findings and Order Nunc Pro Tunc, at ¶ 194 (March 9, 2023) ("2020 GRC Order").

items, such as the 2020 Protocol Qualifying Facility ("QF") Adjustment, are also evaluated without applying the 80% sharing band.[3]

Q. HOW DID ACTUAL NPC IN THE DEFERRAL PERIOD COMPARE TO BASE NPC?

A. Prior to the application of adjustments and allocation to Wyoming, total-company, actual NPC was $2,040,318,302 in the Deferral Period. This compares to Base NPC approved in the 2020 GRC of $1,431,531,607.[4] Thus, on a total-company basis, Actual NPC was $608,786,695, or 43%, higher than Base NPC. This variance is detailed in **Table BGM-2**, below.

Table BGM-2
2020 GRC Base NPC vs. Forecast NPC

Category	2020 GRC	2022 Actuals	Variance	%
Net S.T. Purchases	(116,717,886)	$ 135,625,310	$ 252,343,195	186%
Net L.T. Purchases	534,535,997	544,173,647	9,637,650	2%
Gas	283,645,583	610,525,466	326,879,884	54%
Coal	586,807,806	580,834,961	(5,972,845)	-1%
Wheeling	138,715,539	164,088,727	25,373,188	15%
Other	4,544,569	5,070,191	525,623	10%
Total	**$ 1,431,531,607**	**$ 2,040,318,302**	**$ 608,786,695**	**43%**

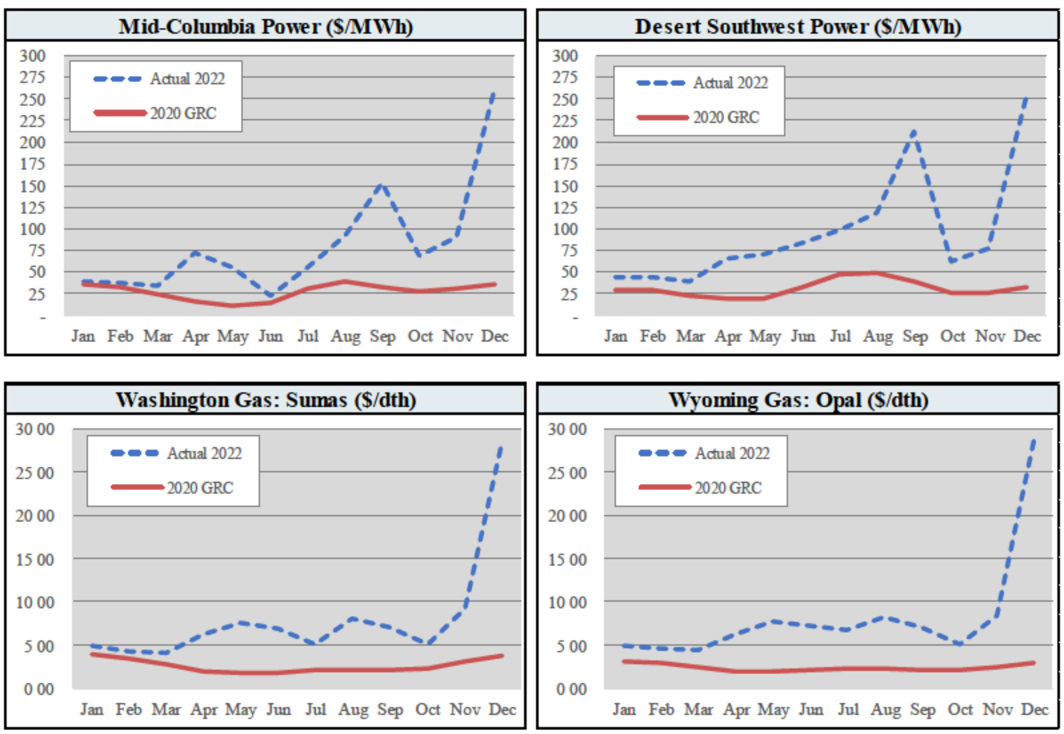
As can be seen, higher natural gas expenses, as well as short term purchased power expenses produced most of the variance. Wheeling expenses were also higher than the GRC forecast, though this change had a smaller impact on overall NPC. Coal costs and long-term purchases were largely in line with the 2020 GRC forecast.

[3] *In the Matter of The Application of Rocky Mountain Power for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement*, Docket No. 20000-572-EA-19 (Record No. 15400), Direct Testimony of Joelle Steward at Exhibit JRS-1 (2020 Multi-State Protocol), at Section 4.4.1.1 & fn. 17 (hereinafter "2020 Protocol").
[4] 2020 GRC Order, Docket No. 20000-578-ER-20, ¶ 192.

Q. WHAT CAUSED THE VARIANCE?

A. A principal driver of the variance between NPC forecast in the 2020 GRC and actual NPC in the Deferral Period was rising market prices. The final NPC study prepared in the 2020 GRC used RMP's June 30, 2020 Official Forward Price Curve ("OFPC"). In **Figure BGM-1**, below, I have performed a comparison between the June 30, 2020 OFPC and actual market prices in 2022.

Figure BGM-1
Market Prices: 2020 GRC vs. 2022 Actual



The actual market prices in **Figure BGM-1** were provided in RMP's Minimum Filing Requirement ("MFR") 2 and MFR 3-1. These actual prices are those published by the Intercontinental Exchange ("ICE"), which represent average prices over the settlement period, and not subject to any volumetric weighting. As can be seen, actual prices for both power and natural gas prices were higher than the June 30, 2020 OFPC used to establish Base NPC. In particular, market dynamics in the second half of 2022 created prices in the months of November and December that were 600%-900% higher than the price forecast used in the 2020 GRC, elevated prices which continued into early 2023.

Q. HAVE MARKET SINCE RETURNED TO MORE NORMAL LEVELS?

A. Yes. Market prices have since subsided and declined considerably. On September 6, 2023, for example, spot prices for natural gas in the Northwest were just \$2.15/dth and spot prices for power in the Northwest were \$55.00/ MWh.[5] For the month of September, the 2020 GRC NPC OFPC forecast assumed Sumas gas prices of \$2.16/Dth and Mid-Columbia market power prices of \$32.37/MWh. Thus, gas prices have declined to 2020 GRC levels, and while power prices remain elevated, they are lower than the levels experienced in 2022: September 2022 Mid-Columbia market prices were \$153.16/MWh.

Q. DOES RMP HAVE POLICIES IN PLACE TO PROTECT RATEPAYERS FROM RISING PRICES?

A. Yes. RMP has a hedging policy which is designed to mitigate the impact of major increases to market prices. It also operates a diverse portfolio of resources, including coal and zero fuel cost renewables, which is also designed to protect ratepayers against increasing energy prices. Notwithstanding, given the increases in NPC that were experienced in 2022, it is apparent that these activities did not necessarily protect ratepayers against the price increase RMP is seeking in this

[5] Energy Information Administration, *Daily Prices* (September 6, 2023). Available at https://www.eia.gov/todayinenergy/prices.php (Accessed September 7, 2023).

docket. Part of this has to do with RMP's failure to follow its hedging policy. Before discussing RMP's hedging policy, however, it is necessary to address an error in the way RMP allocated EIM Settlements to Wyoming.

III. EIM SETTLEMENT ALLOCATION ERROR

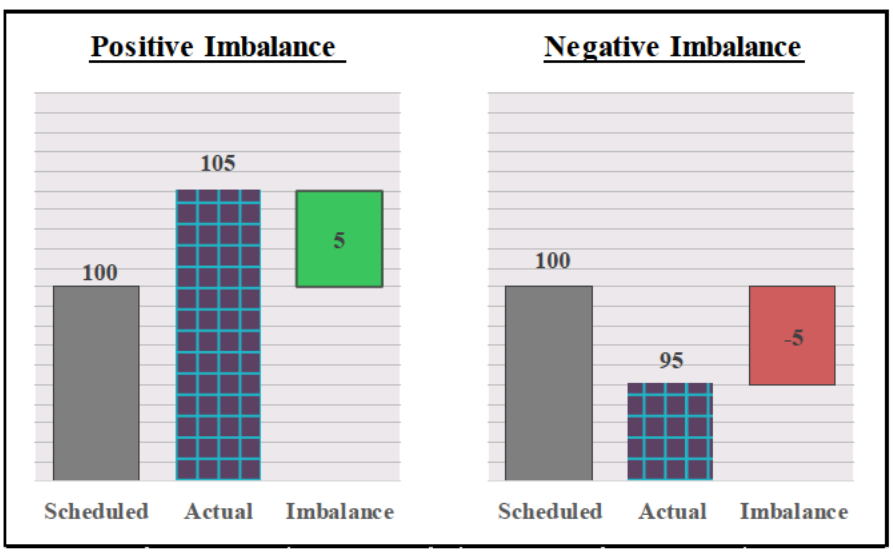
Q. WHAT IS THE ENERGY IMBALANCE MARKET?

A. The EIM is a regional market for imbalance services operated on an hour-ahead, and intra-hour basis by the California Independent System Operator ("CAISO").[6]

Q. WHAT ARE IMBALANCE SERVICES?

A. An imbalance represents the difference between the volume of load or generation scheduled (*i.e.*, planned or forecast) and the actual volume. The concept of an imbalance is described graphically in **Figure BGM-2**, below:

Figure BGM-2
Illustration of Positive and Negative Imbalances from Energy Source (MWh)



[6] *See* California Independent System Operator, *Open Access Transmission Tariff* § 29 (August 2, 2023).

Prior to an operating period, typically an hour, a utility will submit a forecast to its transmission system operator detailing its expected sources and uses of electricity, including both expected generation from network resources and expected loads based on its load forecast. These forecasts are generally referred to as a "schedule." To the extent that the actual sources or uses of electricity vary from the amounts scheduled, the utility will incur imbalance energy, which must be purchased through a service provided by the transmission system operator.

Q. HOW DOES THE EIM CREATE A MARKET FOR IMBALANCE SERVICES?

A. The EIM provides an organized market for imbalance services that is settled in 15-minute and, subsequently, 5-minute intervals over the course of an hour. Instead of having each individual transmission system operator manage imbalances independently, imbalance energy is managed collectively over the entire EIM footprint and settled based on locational marginal prices ("LMPs") calculated by the CAISO's market model. As a part of the market, dispatchable generators are also redispatched relative to their scheduled output to serve imbalance energy across the entire EIM footprint, with the objective of doing so in the most economical way possible. An imbalance can be both positive or negative, resulting in cases where sometimes the market participant must pay the LMP for shortfall imbalance energy and other times it is paid the LMP for its excess imbalance energy.

Q. HOW DOES RMP EARN EIM SETTLEMENT REVENUES BY PARTICIPATING IN THE MARKET?

A. In the hour-ahead, all market participants must submit schedules that balance their individualized system, meaning that all scheduled generation and scheduled load must be equal. The CAISO market model, however, reoptimizes the sub-hourly dispatch for the entire EIM footprint, subject to the actual operating costs and capabilities of dispatchable resources and transfer limitations between participants. Over the course of an hour, the market will provide instructions for dispatchable resources to dispatch up or dispatch down, relative to the scheduled output to serve the footprint more efficiently. These instructions are referred to as an "Instructed Imbalance." In contrast, an "Uninstructed Imbalance" occurs when the actual energy from a non-dispatchable resource or a load is different from the forecasted schedule. Responding to market instructions is the principal source of EIM Settlement revenues for RMP. Since actual energy of non-dispatchable resources and loads is sometimes higher and other times lower than the forecasted schedule, Uninstructed Imbalance is not typically a principal source of EIM Settlement revenue.

Q. WHAT TOTAL AMOUNT OF EIM SETTLEMENT REVENUES DID RMP RECOGNIZE IN THE DEFERRAL PERIOD?

A. Actual NPC for 2022 included $294,703,565 of revenues from EIM Settlements.[7]

[7] Confidential RMP Exhibit 2.2, at p. 6 (the EIM Settlement value in not confidential).

Q. WHAT AMOUNT OF INSTRUCTED IMBALANCE REVENUES DID RMP RECOGNIZE IN THE DEFERRAL PERIOD?

A. In the Deferral Period RMP received EIM Settlement proceeds of $[redacted] for Instructed Imbalance energy in the 15-minute market,[8] and RMP made payments of $[redacted] for Instructed Imbalance energy in the 5-minute market.[9] In contrast, RMP received EIM Settlement proceeds of just $[redacted] for Uninstructed Imbalance revenues in the Deferral Period.[10]

Q. ARE THERE OTHER TYPES OF SETTLEMENTS IN THE EIM?

A. Yes. As noted in the CAISO's tariff, there are many other settlements and uplift charges associated with EIM participation. In the Deferral Period, for example, RMP earned congestion revenues of $[redacted];[11] marginal loss revenues of $[redacted];[12] and greenhouse gas revenues of $[redacted].[13]

Q. HAS THE COMMISSION DECIDED HOW TO ALLOCATE EIM SETTLEMENTS?

A. Yes. In setting Base NPC in the 2020 GRC, the Commission was unequivocal when it required RMP to use of the System Energy ("SE"), not the SG factor, to allocate EIM Settlements to Wyoming. The Commission stated:

> For the allocation of EIM settlements, we conclude that allocation on a SE basis rather than a SG basis is a more accurate reflection of costs in Wyoming and more consistent with the character of EIM transactions. Unlike RMP, we do not believe the Multi-State Protocol requires use of the SG factor. Allocation on a SG basis

[8] *See* Confidential MFR 1.
[9] *Id.*
[10] *Id.*
[11] *Id.*
[12] *Id.*
[13] *Id.*

> results in Wyoming paying more of the cost of producing power and receiving less of the benefit from reselling that power produced in firm wholesale markets. Given that Wyoming is a net exporter of energy, changing the allocation of EIM settlements to a SG factor aligns costs and benefits more closely to reality.[14]

Q. WHY DID THE COMMISSION DECIDE TO ALLOCATE EIM SETTLEMENTS USING THE SE FACTOR IN THE 2020 GRC?

A. In the 2020 GRC, WIEC filed testimony demonstrating that EIM Settlements were not considered Wholesale Contracts or Short-Term Purchases and Sales,[15] as defined in the 2020 Protocol.[16] Accordingly, EIM Settlements fell under the definition of Non-Firm Purchases and Sales, which according to the 2020 Protocol, are "classified as 100 percent Energy-Related" and allocated using the SE factor.[17] Further, WIEC demonstrated that failure to allocate EIM settlements on an SE factor operated to the detriment of Wyoming ratepayers. Specifically, Wyoming uses more energy but less capacity than other states. As a result, Wyoming ends up paying more of the cost of producing power but receives less benefits from reselling the power that is produced in firm wholesale markets.[18] In the Final Order in the 2020 GRC, the Commission agreed with WIEC's recommendation and concerns stating, "Rocky Mountain Power shall allocate Energy Imbalance Market

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[14] 2020 GRC Order, Docket No. 20000-578-ER-20, ¶ 196.
[15] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $7.1 Million Per Year or 1.1 Percent, to Revise the Energy Cost Adjustment Mechanism, and to Discontinue Operations at Cholla Unit 4*, Docket No. 20000-578-ER-20 (Record No. 15464), WIEC Exhibit 302, Direct Testimony of Bradley G. Mullins, pp. 26-30.
[16] 2020 Protocol, Appendix A, at p. 7.
[17] 2020 Protocol at Section 3.1.1.
[18] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $7.1 Million Per Year or 1.1 Percent, to Revise the Energy Cost Adjustment Mechanism, and to Discontinue Operations at Cholla Unit 4*, Docket No. 20000-578-ER-20 (Record No. 15464), WIEC Exhibit 302, Direct Testimony of Bradley G. Mullins, p. 29.

settlements on a System Energy (SE) basis in the Company's Generation and Regulation Initiative Decision [("GRID")] modeling"[19]

Q. IS RMP REQUIRED TO USE THE SAME ALLOCATION METHOD IN THE ECAM?

A. Yes. Page 2 of Schedule 95, for example, states that Adjusted Actual NPC shall "include applicable Commission-adopted adjustments from the most recent general rate case."[20] Further, RMP's GRID model (which has since been replaced with AURORA) was used to develop Base NPC. Calculations of Actual NPC in ECAM filings must use the same allocation factors as Base NPC to form an appropriate apples-to-apples comparison of cost. A contrary conclusion would render the Commission's decision in RMP's GRC meaningless.

Q. CAN YOU EXPAND ON WHY USING THE SE FACTOR IS APPROPRIATE IN WYOMING?

A. As WIEC pointed out in RMP's 2020 GRC, Wyoming has the highest load factor of any of RMP's jurisdictions, and as a result, the difference between the SE and SG factors for Wyoming is material. In the Deferral Period, for example, the Wyoming SE factor was 15.475% versus an SG Factor of 13.701%.[21] Therefore, if the SG factor is used, rather than the approved SE factor, Wyoming ratepayers will be allocated 1.774% less of their share of EIM Settlement revenues.

[19] 2020 GRC Order, Docket No. 20000-578-ER-20, ¶ 19.
[20] RMP Schedule 95, Sheet No. 95-2.
[21] Confidential RMP Exhibit 2.2 at p. 29 (the allocation factor percentages are not confidential).

Q. DOES WYOMING'S HIGH LOAD FACTOR MEAN IT IS ALLOCATED MORE ENERGY-RELATED COSTS?

A. Yes. As demonstrated in the 2020 GRC and mentioned above, having a higher SE factor means that Wyoming is otherwise allocated a higher portion of energy-related costs, such as the cost of fuel from coal and natural gas fired generators. This is of note because much of RMP's fuel cost is incurred in connection with responding to EIM instructions and in generating EIM Settlement revenues.

Q. DID RMP COMPLY WITH THE COMMISSION'S ORDER REQUIRING EIM SETTLEMENTS TO BE ALLOCATED USING THE SE FACTOR?

A. No. Actual NPC for 2022 included $294,703,565 of revenues from EIM Settlements.[22] This revenue represents the gross proceeds RMP received from its participation in the EIM in the Deferral Period. In Confidential Exhibit 2.2, Page 6, RMP classified these EIM Settlements as "Post-merger Firm,"[23] which RMP allocates to Wyoming using the System Generation ("SG") factor.[24] Based on the Commission's unequivocal direction to allocate EIM Settlements using the SE factor, RMP erred in this docket by using the SG factor to allocate EIM Settlements.

[22] Confidential RMP Exhibit 2.2, at p. 6 (the EIM Settlement value in not confidential). The specific settlement transactions may be found in MFR 1 by filtering column "External Legal Entity" on "CISO – LE" and column "FERC" on "EX."
[23] The classification of EIM Settlements as "Post-merger Firm" in Confidential Exhibit 2.2. is not confidential.
[24] *See* the Workpaper version of Confidential Exhibit 2.2, Tab "(2.2.1) WY Allctd Actual NPC", Cells "T60" and "U60."

Q. ARE EIM SETTLEMENT REVENUES IN ACTUAL NPC DIFFERENT FROM THE EIM NET BENEFITS EVALUATED IN THE 2020 GRC?

A. Yes. The EIM Settlement revenues in actual NPC are the *gross* proceeds from the EIM, and do not include the cost of fuel incurred to generate those proceeds. In contrast, EIM Net Benefits evaluated in a general rate case include both the *gross* proceeds and the incremental fuel costs associated with the EIM Settlement instructions. The GRID model (and now AURORA) used to calculate Base NPC is an hourly model, which does not consider the incremental fuel cost of responding to imbalances within an hour. Therefore, in a rate case forecast, it is necessary to consider both the incremental EIM Settlement revenues and the associated fuel costs consumed to generate those revenues when considering the impact of the EIM on the overall NPC calculated in GRID. In actual NPC, however, the EIM Settlement revenues and the corresponding costs are recorded separately.

Q. WHAT EIM NET BENEFITS WERE INCLUDED IN BASE NPC?

A. In Base NPC, RMP calculated total-company EIM Net Benefits of $46,050,235,[25] which as noted, included both the EIM Settlement revenues and the assumed fuel cost associated with generating those revenues.[26]

[25] *See In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $7.1 Million Per Year or 1.1 Percent, to Revise the Energy Cost Adjustment Mechanism, and to Discontinue Operations at Cholla Unit 4*, Docket No. 20000-578-ER-20 (Record No. 15464), RMP Exhibit 13.3, Rebuttal Testimony of David G. Webb, Exhibit RMP___(DGW-1R), p. 5.

[26] *See In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $7.1 Million Per Year or 1.1 Percent, to Revise the Energy Cost Adjustment Mechanism, and to Discontinue Operations at Cholla Unit 4*, Docket No. 20000-578-ER-20 (Record No. 15464), RMP Exhibit 13.3, Rebuttal Testimony of David G. Webb, p. 30.

Q. WHAT EIM NET BENEFITS WERE RECOGNIZED IN THE DEFERRAL PERIOD?

A. Because the fuel costs incurred to generate EIM Settlement revenues are unknown, the precise level of EIM Net Benefits in the Deferral Period is also unknown. While the Deferral Period included $294,703,565 of EIM Settlement revenues, that gross amount does not consider any of the associated fuel costs necessary to generate those revenues. The EIM-related fuel costs are accounted for as ordinary fuel expense and assigned to the individual power plants where the fuel was consumed. Considering the magnitude of the EIM Settlement revenues, however, one can assume that the EIM Net Benefits in the Deferral Period were greater than the level included in Base NPC. Put differently, EIM Net Benefits equal EIM Settlement revenues minus fuel costs incurred to generate those revenues. Because RMP assumed only $46,050,235 of EIM Net Benefits in Base NPC but received $294,703,565 of EIM Settlement revenues in the Deferral Period, RMP's fuel costs to generate those revenues would need to equal $248,653,330 for actual EIM Net Benefits to be less than the amount assumed in the 2020 GRC.

Q. IS THE FACT THAT THE ACTUAL NET BENEFIT IS UNKNOWN A VALID REASON TO USE A DIFFERENT ALLOCATION METHOD FOR EIM SETTLEMENT REVENUES?

A. No. In calculating Wyoming-allocated actual NPC, EIM-related fuel costs are already being allocated using the SE factor. Wyoming is getting a higher share of the cost of fuel necessary to generate EIM Settlement revenues. Accordingly, to properly allocate the EIM Net Benefits, consistent with the way those were calculated in Base NPC, it is necessary to allocate both the gross EIM Settlement revenues and the associated fuel costs using the SE factor. Since the fuel cost are already being allocated using the SE factor, it is therefore necessary to apply the SE factor to the entirety of the $294,703,565 in EIM Settlement revenues.

Q. WHAT HARM RESULTS IF EIM SETTLEMENTS ARE ALLOCATED DIFFERENTLY THAN EIM-RELATED FUEL COSTS?

A. RMP's use of the SG factor for the gross EIM Settlement revenues would result in a mismatch between EIM costs and benefits. RMP allocated the EIM Settlement revenues using the SG factor but the fuel costs necessary to generate those revenues using the SE factor. In other words, even if RMP's filed case in this proceeding did not directly contradict the Commission's required allocation methodology as discussed above, RMP's approach would nevertheless be unfair because it results in Wyoming customers receiving more of the costs and less of the benefit associated with the EIM. While the precise amount of fuel costs necessary to generate the EIM Settlement revenues may be unknown, the amount must have been significant, given the magnitude of the EIM Settlement revenues. Therefore, the effects of this mismatch are also likely significant.

Q. WHAT DO YOU RECOMMEND?

A. It was an error for RMP not to allocate EIM Settlements using the SE factor as required by the Commission in the 2020 GRC. RMP's use of the SG factor for EIM Settlement revenues is also inconsistent with the way that the fuel costs used to generate EIM Settlement revenues are being allocated to Wyoming customers. Accordingly, I recommend that the approved allocation method, for both the EIM

Settlement revenues and the associated EIM-related fuel costs, be applied when calculating Wyoming-allocated actual NPC in the ECAM.

Q. WHAT IS THE IMPACT OF THIS ERROR ON THE ECAM BALANCE?

A. The impact is material. As detailed on Page 2 of **WIEC Exhibit 200.2**, correcting this error results in a $5,227,776 reduction to Wyoming-allocated actual NPC. Correspondingly, it produces a $4,344,168 reduction to the ECAM balance after the application of the 80% sharing band and interest.

IV. <u>2022 ECAM EIM SETTLEMENT ALLOCATION ERROR</u>

Q. DID RMP ALLOCATE EIM SETTLEMENTS CORRECTLY IN THE 2022 ECAM?

A. No. In the 2022 ECAM,[27] RMP allocated EIM Settlement revenues using the SG factor, not the SE factor. The 2022 ECAM encompassed actual NPC incurred in calendar year 2021. The Commission Order in the 2020 GRC requiring the change to the SE factor was effective beginning July 1, 2021. Therefore, over the period July 1, 2021 through December 31, 2021, RMP allocated EIM Settlement revenues in a manner that was inconsistent with the Commission Order in the 2020 GRC.

Q. WHAT EIM SETTLEMENT REVENUES WERE RECOGNIZED IN 2021?

A. The relevant parts of RMP's 2022 ECAM filing are attached as **Confidential WIEC Exhibit 200.3**. In 2021, RMP recognized $191,498,842 of EIM Settlement revenues.[28] As discussed above, this amount did not include any of the fuel costs

[27] *In the Matter of the Application of Rocky Mountain Power to Increase Current Rates by $27.8 Million to Recover Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates by $ 1.6 Million Under Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism*, Docket No. 20000-617-EM-22 (Record No. 17037).
[28] Confidential WIEC Exhibit 200.3 at 5 (the EIM Settlement value is not confidential).

necessary to generate those revenues. Of that amount $150,337,249 of EIM Settlement revenues were recognized after the July 1, 2021 effective date of the 2020 GRC.[29]

Q. HOW DO YOU KNOW THAT EIM SETTLEMENT REVENUES WERE ALLOCATED INCORRECTLY?

A. Like this docket, in the 2022 ECAM, RMP classified EIM Settlement revenues as "Post-Merger Firm"[30] In Exhibit RMP___JP-3, Pages 1 and 2, Post Merger Firm power purchases were allocated using the SG factor.[31] Accordingly, EIM Settlement in the 2022 ECAM were incorrectly allocated using the SG factor.

Q. WHAT WAS THE IMPACT OF THE ERROR ON THE 2022 ECAM?

A. In the 2022 ECAM, Wyoming's SE factor was 15.380% and its SG factor was 13.638%.[32] As detailed in **WIEC Exhibit 200.2**, Page 2, the impact of improperly allocating the post July 1, 2021 EIM Settlement revenues using the SG factor, rather than the SE factor was a $2,339,629 overstatement of Wyoming-allocated NPC. After application of the 80% sharing band and interest through December 31, 2021, this amounted to a $1,881,491 error in the 2022 ECAM balance.

[29] *Id.*
[30] *Id.*
[31] Use of the SE factor can be noted in the Excel version of the referenced exhibit on Tab "(3.1) WY Allctd Actual NPC," Cells "T60" and "U60"
[32] Confidential WIEC Exhibit 200.3 at 6 (the allocator percentages are not confidential).

Q. WAS THIS ERROR RESOLVED IN THE STIPULATION IN THE 2022 ECAM?

A. No. The allocation of EIM Settlements was not among the issues that were addressed or resolved in the 2022 ECAM Stipulation.[33] Other than a correction identified in RMP's Rebuttal Testimony, the 2022 ECAM Stipulation only made two adjustments: 1) removing the mark-to-market adjustment for Utah Schedules 32 and 34; and, 2) removing the WRAP fee.

Q. IS IT APPROPRIATE TO MAKE A CORRECTION FOR EIM SETTLEMENTS IN THIS DOCKET?

A. Yes. Where material errors are identified in prior years' commodity balancing accounts, which result in *overcollection* from ratepayers, the Commission has historically corrected the error through an adjustment to the going forward balance.[34] The propriety of a correction is further implicated by the fact that this particular error was the result of RMP not complying with clear instructions in a Commission order. It is also consistent with the treatment of similar corrections in recent ECAM proceedings.

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[33] *In the Matter of the Application of Rocky Mountain Power to Increase Current Rates by $27.8 Million to Recover Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates by $ 1.6 Million Under Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism*, Docket No. 20000-617-EM-22 (Record No. 17037), Stipulation and Settlement Agreement, ¶5.

[34] *MGTC, Inc. v. Pub. Serv. Comm'n of Wyo.*, 735 P.2d 103, 107 (Wyo. 1987) (noting that the equities in the case "dictate that MGTC should not be permitted to reap the windfall of overcharges that it collected by misapplying the provisions of its filed tariff"); *see also Mont.-Dakota Utils., Co. v. Pub. Serv. Comm'n of Wyo.*, 332 P.3d 1160, 1164 (Wyo. 2014) (holding that an adjustment to correct errors made in prior adjustment mechanism filings did not violate the prohibition against retroactive ratemaking, where MDU sought "to retain the financial benefits it received, at the expense of its customers, based on errors of its own creation").

Q. HAVE SIMILAR CORRECTIONS BEEN MADE IN PRIOR ECAM PROCEEDINGS?

A. Yes. In the 2021 ECAM, for example, RMP discovered that it had, in the 2020 ECAM, incorrectly allocated the cost of the Embedded Cost Differential ("ECD") to Wyoming.[35] RMP proposed a corrective adjustment to the 2021 ECAM balance for the prior year's error. As RMP noted in testimony, the purpose of the line item titled "2020 ECAM ECD Adjustment" in the 2021 ECAM calculation was to correct the $254,558 that "was inadvertently excluded from the 2020 ECAM amount."[36]

Q. DID WIEC SUPPORT MAKING THE 2020 ECAM ECD ADJUSTMENT CORRECTION?

A. In Direct Testimony WIEC initially opposed making the 2020 ECAM ECD Adjustment correction, noting that the Commission had historically approved such corrections when utilities had overcharged ratepayers, which was not the case with the ECD Adjustment correction.[37] Notwithstanding, WIEC ultimately supported making the correction in the context of a Stipulation in that docket, albeit excluding

[35] *In the Matter of the Application of Rocky Mountain Power to Decrease Current Rates by $14.9 Million to Refund Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates by $166 Thousand Under Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism*, Docket No. 20000-599-EM-21 (Record No. 15767), Direct Testimony of Jack Painter, pp. 11-12.
[36] *Id.*
[37] *In the Matter of the Application of Rocky Mountain Power to Decrease Current Rates by $14.9 Million to Refund Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates by $166 Thousand Under Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism*, Docket No. 20000-599-EM-21 (Record No. 15767), Direct Testimony of Bradley Mullins, pp. 11-15.

interest on the correction amount.[38] The Commission ultimately approved the Stipulation.[39]

Q. WHAT DO YOU RECOMMEND IN THIS CASE?

A. Since this error will otherwise result in material overcollection of NPC from the 2022 ECAM, I recommend an adjustment to this years' ECAM to make the correction.

Q. DO YOU RECOMMEND INCLUDING INTEREST ON THE CORRECTION?

A. Yes. Considering the specific circumstances surrounding this error and the fact that RMP did not comply with the Commission Order in the 2020 GRC, I recommend refunding to customers the full impact of the error in this case, inclusive of interest.

Q. WHAT IS THE IMPACT OF THIS CORRECTION INCLUDING INTEREST?

A. Inclusive of interest accrued in both the 2022 ECAM Deferral Period and the Deferral Period in this docket, the impact of making the correction, as I have recommended, is a $1,973,714 reduction to the 2023 ECAM balance.

[38] *In the Matter of the Application of Rocky Mountain Power to Decrease Current Rates by $14.9 Million to Refund Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates by $166 Thousand Under Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism*, Docket No. 20000-599-EM-21 (Record No. 15767), Stipulation and Settlement Agreement, ¶ 1.

[39] *In the Matter of the Application of Rocky Mountain Power to Decrease Current Rates by $14.9 Million to Refund Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates by $166 Thousand Under Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism*, Docket No. 20000-599-EM-21 (Record No. 15767), Memorandum Opinion, Findings and Order Approving Stipulation, Ordering ¶ 1 (Feb. 11, 2022).

V. HEDGING POLICY

Q PLEASE SUMMARIZE YOUR CONCERNS WITH RMP'S HEDGING PROGRAM IN THE DEFERRAL PERIOD?

A. RMP's hedging program plays a critical role in protecting ratepayers against rising prices by stabilizing and mitigating the impacts of price fluctuations. As noted, a key driver of the increased actual NPC in the Deferral Period, and the recovery RMP is seeking through the ECAM, was the major increases in market prices that occurred in the second half of 2022. The ECAM rate increase RMP is requesting because of heightened market prices is significant. Accordingly, it is apparent that RMP's hedging practices were not successful in mitigating the impact of higher prices in the Deferral Period.

Q. WHAT ARE YOUR CONCERNS WITH RMP'S HEDGING ACTIVITIES IN THE DEFERRAL PERIOD?

A. Foremost, the currently effective hedging policy is overly simplistic, based on arbitrary percentages and applied too broadly to capture key risks inherent in RMP's system. For example, I believe RMP has applied its gas hedging program in a way that ignores the unique risks associated with its gas plants in the northwest. [redacted] Finally, RMP's power hedging policy's estimation of its power position appears to fall short of reality.

A. RMP'S Hedging Policies

Q. WHAT IS HEDGING?

A. Hedging is not about beating the market. Hedging is a risk management strategy employed by utilities to protect themselves and their ratepayers from adverse price movements and unforeseen events. It is not focused on trying to outperform the market or make speculative profits. In essence, hedging involves pre-purchasing an energy commodity at a predetermined price before its actual consumption. By securing a fixed price for the commodity in advance, a hedging utility reduces its exposure to market prices and market price changes during the consumption period, often referred to as the "Prompt Period" or "Prompt Month." In doing so, the utility does not eliminate its exposure to the market. Instead, the consequences of both rising and falling market prices are distributed more evenly across time.

Q. WHAT FORWARD HEDGING PRODUCTS ARE AVAILABLE TO RMP?

A. Forward hedging products for natural gas and power are available in a range of markets, including both bilateral markets and through commodity exchanges, such as Intercontinental Exchange, the Chicago Mercantile Exchange, and the New York Mercantile Exchange. Hedging contracts can be both physical or financial products. A physical hedging contract provides for delivery of the underlying commodity at a specific location at a fixed price. Alternatively, financial hedging products, such as a swap, provide similar hedging characteristics as a physical transaction, albeit settled based on published index prices without the underlying commodity. The practicality of a physical versus financial hedging transaction varies based on the specific circumstances and markets involved. RMP, for example, [redacted].

Q. WHAT IS A SWAP?

A. Swaps are the primary instrument used by utilities for implementing financial hedging. A swap contract is an agreement between two counterparties to exchange a fixed price with a floating index price. Natural gas and power swaps usually involve settlement periods that last for a month or a quarter. With a swap, the hedging utility is paid, or must pay, the difference between the agreed-upon fixed price and the actual market index price. If prices go up, the utility receives a financial payment offsetting the increased cost of purchasing gas in the market; if prices go down, however, the utility must make a financial payment offsetting the benefit of the declining prices. Assuming the settlement index price is the same as the prices the utility pays to acquire the underlying commodity, the net cost to the utility (*i.e.*, the cost of purchasing the commodity, less the payout from the swap) is the fixed price of the swap.

Q. WHERE IS RMP'S HEDGING POLICY DOCUMENTED

A. RMP's internal hedging policy is established in its "Energy Risk Management Policy." In response to WIEC Data Request 2.1, RMP provided each of its Energy Risk Management Policy documents in effect over the period January 1, 2019 through May 31, 2023. RMP's currently effective hedging policy is attached as **Confidential WIEC Exhibit 200.4**. [redacted]

[redacted]).

Q. HAS RMP RECENTLY CHANGED ITS HEDGING POLICY.

A. Yes. Effective July 1, 2021, RMP changed its hedging policy. Prior to that date, RMP's policy was based on a [redacted]. The prior hedging policy is attached as **Confidential WIEC Exhibit 200.5**. Because transactions included in the Deferral Period were executed under both the new and the old policy, both policies are at issue in this case.

Q. PLEASE DESCRIBE RMP'S CURRENTLY EFFECTIVE HEDGING POLICY.

A. On May 19, 2021, RMP provided a presentation to the Commission describing its new hedging policy. I have attached that presentation as **Confidential WIEC Exhibit 200.6**.[40] As can be seen, RMP's currently effective policy is straightforward, [redacted] Limits apply to both gas and power hedges and are detailed in **Confidential Table BGM-3**, below.

[40] Provided in Response to WIEC Data Request 2.5.

Confidential Table BGM-3

<u>PacifiCorp Hedging Limits</u> [redacted]

[redacted]

Q. HOW DOES RMP CALCULATE ITS NATURAL GAS REQUIREMENTS WHEN APPLYING ITS HEDGING LIMITS?

A. In response to WIEC Data Request 2.8, RMP provided the models that it used to calculate its hedging requirements, which RMP employs to evaluate whether it is within the above hedging limits. In **Confidential WIEC Exhibit 200.7,** I have attached the hedging position report from September 30, 2021. [redacted]

[redacted].

Q. HOW DOES RMP CALCULATE ITS POWER REQUIREMENTS WHEN APPLYING ITS HEDGING LIMITS?

A. [redacted]

Q. DO YOU HAVE ANY CONCERNS WITH RMP'S OVERALL POLICY?

A. [redacted] Many utilities conduct trading activities under a long-term strategy, a mid-term strategy, and a short-term strategy, where the granularity of hedging activities becomes increasingly more granular as the prompt period becomes

[41] *See e.g.*, Confidential WIEC Exhibit 200.7.

nearer. [redacted]

Q. HOW DID RMP CALCULATE THE [redacted]?

A. [redacted]

Q. IS IT REASONABLE TO [redacted]?

A. [redacted]

Q. HOW DOES THE CURRENT POLICY COMPARE TO RMP'S PRIOR POLICY?

A. [redacted]

[redacted] are detailed in **Confidential Table BGM-4** below:

Confidential Table BGM-4

[redacted]

[redacted]

Q. WAS RMP'S [redacted] HEDGING EFFECTIVE?

A. No. Notably, the Final NPC approved in the 2020 GRC was submitted in September 2020. At the time of the 2020 GRC, [redacted] Given the 43% increase to NPC presented in this case, [redacted] was not effective in meeting the designed limits, albeit recognizing that RMP would have subsequently hedged differently if the policy had remained in place.

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[42] Confidential WIEC Exhibit 202.4, p. 4.

B. <u>Natural Gas Hedging</u>

Q. WHAT PORTION OF RMP'S GAS REQUIREMENTS WERE HEDGED IN THE DEFERRAL PERIOD?

A. RMP's physical gas requirements may be found in Confidential MFR 3-2. RMP's natural gas hedges were detailed in Confidential MFR 3-3. In **Confidential WIEC Exhibit 200.8,** I have performed a comparison between the natural gas swaps provided in Confidential MFR 3-3 to the natural gas supply requirements provided in Confidential MFR 3-2. Using this information, I calculated the percentage of natural gas that was hedged in each month prior to the prompt month. This analysis was performed separately for each month in the Deferral Period. The analysis was also detailed for its westside natural gas plants (*i.e.*, Chehalis and Hermiston) and for RMP's eastside natural gas plants (*i.e.*, Lakeside, Currant Creek, Gadsby, and Naughton). I also performed an analysis based on RMP's total-company gas requirements. As can be seen, RMP was hedged at various levels in the Deferral Period. The hedging levels also varied by months and the number of months ahead of the prompt period. An annual summary of that analysis is detailed in **Confidential Figure BGM-3,** below:

Confidential Figure BGM-3
RMP Gas Hedging Percentages by Month Ahead of Prompt Month – Average of all Months in Deferral Period

[redacted]

[redacted]

Q. HOW DOES RMP PURCHASE NATURAL GAS FOR ITS POWER PLANTS?

A. [redacted] Firm index gas supply products are commonly used in the natural gas industry and provide rights to physical gas supply at a particular delivery point and settled at monthly, First of Month ("FOM") index prices. The prices for these FOM market index products are settled based on average market prices for monthly natural gas

[43] *See* Confidential MFR 3-2.

transactions cleared in the week prior to the first of the month, also known as the Bid Week. The monthly market prices used for index gas are, therefore, different from the cost of gas purchased in daily markets over the course of a month. The ICE market prices reported in MFR 3-1, for example, represent the average daily price of natural gas, rather than the FOM prices used as the market index for most of RMP's physical gas supply. In the Deferral Period approximately [redacted]% of RMP's gas requirements were acquired using FOM index products, whereas the remaining [redacted]% of gas was acquired in daily gas markets.

Q. WHY WERE THE WEST-GAS [redacted]?

A. [redacted]

Q. WHY IS THIS PROBLEMATIC?

A. RMP's gas plants in the east and west are exposed to different markets with different risks. The gas plants on the eastside are exposed primarily to the Rockies markets. In contrast, the gas plants in the West are exposed primarily to the Sumas market.

Q. ARE SUMAS AND ROCKIES MARKETS EQUALLY RISKY?

A. No. While sometimes these two markets trade in tandem, often they do not, particularly in the winter months. Because of limitations of pipeline capacity and limited storage capability in the Northwest, Sumas can be viewed as a riskier market than the Rockies market. California is also heavily dependent on imports from Sumas, making the market more susceptible to west coast demands. As can be noted in **Confidential Exhibit WIEC 200.8**, however, [redacted].

Q. WERE SUMAS PRICES HIGHER THAN ROCKIES PRICES IN 2022?

A. Yes. In **Confidential Table BGM-5**, below, I detail both the FOM and ICE monthly market prices for Sumas and Rockies in the Deferral Period.

Confidential Table BGM-5
<u>FOM and ICE Monthly Market Prices at Sumas and Rockies $/dth</u>

[redacted]

Several things can be observed from the above table. [redacted]

[redacted] This likely reflects the higher risk at Sumas associated with limited storage and pipeline capability in the Northwest and Pacific regions.

Q. WAS IT PRUDENT FOR RMP [redacted]?

A. No. [redacted].

Q. WAS RMP ADEQUATELY HEDGED IN EVERY MONTH?

A. [redacted].

Confidential Figure BGM-4

Hedging Percentage by Month at 12-Month Intervals Before Prompt Month

[redacted]

[redacted]

Q. BASED ON YOUR REVIEW, WHAT DO YOU RECOMMEND?

A. Based on my review, two aspects of RMP's natural gas hedging activities were imprudent, for which I recommend a disallowance.

[redacted]

Q. HOW DO YOU PROPOSE TO CALCULATE THIS DISALLOWANCE?

A. To calculate these disallowances, I used the OFPCs that were issued over the [redacted] hedging window. I calculated the hedges that would have been necessary [redacted]. I priced those hedges based on the forward pricing in the OFPC in effect for the Deferral Period at the time the incremental hedges would have been executed. I then calculated the hedging benefit that RMP would have recognized if it had executed the incremental hedges. I performed the analysis first for the westside gas plants, and then again for the eastside gas resources for the months of April through June, including the incremental hedging volumes assumed in the disallowance related to the westside plants. The disallowance calculation for the westside plants may be found in **Confidential WIEC Exhibit 200.9.** The disallowance calculation for the months of April through June may be found in **Confidential WIEC Exhibit 200.10**.

Q. WHAT WAS THE IMPACT OF YOUR DISALLOWANCE CALCULATION?

A. As can be seen, based on my analysis, I am recommending a natural gas total hedging disallowance of $51,793,485 on a total-company basis, consisting of $43,796,113 for RMP's failure to hedge its westside gas plants and a further $7,997,372 total-company amount representing RMP's under-hedging in April through June. On a Wyoming allocated basis, these two items result in a total disallowance of $8,014,925, consisting of $6,777,349 for RMP's failure to hedge its westside gas plants and $1,237,575 for RMP's under-hedging in the months of April through June. After application of 80% sharing and interest, these disallowances produce a $6,661,399 reduction to the 2023 ECAM balance, with $5,629,525 attributable to RMP's failure to hedge its westside gas plants and $1,031,874 attributable to RMP's under-hedging in the months of April through June.

C. <u>Power Hedging</u>

Q. PLEASE SUMMARIZE THE POWER HEDGING ANALYSIS THAT YOU PERFORMED?

A. In **Confidential WIEC Exhibit 200.11**, I perform a power hedging analysis, similar to the one performed for natural gas. The power hedging analysis uses power trade data provided in Confidential MFR-1. With that data I filtered for short-term purchase and sales transactions. I segregated these transactions into three categories: hedging, day-ahead and real time. I also removed various trades related to losses, reserve sharing and out of period adjustments. For each month, I evaluated the total requirements as the average net purchases for any given monthly period. Note that RMP's hedging policy applies a different approach by focusing on the highest daily average purchase level. Not having the data to determine the highest daily average purchase level in a particular month, I relied on the average net purchase level within a month to determine the hedging requirements. Using the calculated level of requirements for each month, I calculated the percentage hedged for each month leading up to the prompt month. I performed this calculation three times—once for the eastside, once for in for the westside, and again for the total-company.

Q. WHAT DID YOU FIND?

A. **Confidential Figure BGM-5**, below, summarizes the results of my analysis.

Confidential Figure BGM-5
<u>RMP Power Hedging Percentages by Month Ahead of Prompt Month – Average of all Months in Deferral Period</u>

[redacted]

RMP's power hedging position presents a more complicated scenario than its gas hedging position. [redacted]

[redacted] Accordingly, in the above figure, it is challenging to draw conclusions about the effectiveness of RMP's power hedging practices. Notwithstanding, [redacted]

Q. DID RMP SELL ANY HEDGES IN THE DEFERRAL PERIOD?

A. [redacted]

Q. WAS IT PROBLEMATIC THAT RMP SOLD HEDGES IN ADDITION TO BUYING THEM?

A. Making sales in forward markets is a common activity. Notwithstanding, [redacted], it exposed ratepayers to greater market risk. When spot prices were ultimately higher than expected at the time the transactions were executed, this practice effectively results in RMP having to buy the power in the market and then sell it at a loss. Since ratepayers are otherwise exposed to the market, a less risky strategy would have been to simply sell excess power short-term markets, rather than speculating in forward markets.

Q. WHAT LOSSES DID RATEPAYERS INCUR AS A RESULT OF THESE FORWARD SALES?

A. In **Confidential WIEC Exhibit 200.11**, I provide detail of the specific forward sales transactions that settled in the Deferral Period. In total there were [redacted] different sales hedging transactions int the Deferral Period. The cost of these hedge sales transactions relative to the monthly average market price was $28,188,276 or $4,362,072 allocated to Wyoming.

Q. WHAT DO YOU RECOMMEND?

A. I have reservations regarding the comprehensiveness of RMP's current hedging policy when it comes to evaluating the risks associated with its long position on the eastside and its short position on the westside. Nevertheless, after reviewing the available information, I have not found sufficient evidence to propose a disallowance with respect to RMP's power hedging practices in this docket.

Accordingly, my recommendation is for the Commission to encourage RMP to adopt a more holistic approach to its power hedging—one that encompasses evaluation of risks related to both forward purchases and sales transactions, in addition to considering their interplay with the costs of alternative power sources like gas and coal. Given the interdependencies between RMP's east and west positions, it's important to acknowledge that a simple percentage-based policy for power may not achieve the desired hedging outcomes.

VI. <u>WIND CAPACITY FACTORS</u>

Q. PLEASE SUMMARIZE THE ANALYSIS YOU PERFORMED RELATED TO RMP'S WIND PLANTS?

A. In the 2020 GRC, the Commission approved capital additions related to Energy Vision 2020 and Repowering. Energy Vision 2020, including the Pryor Mountain Wind Facility, encompassed the addition of approximately 1,189 MW of new wind capacity, and the repower program resulted in the rebuilding of approximately 1,065 MW of existing wind capacity. WIEC has been concerned with the performance of RMP's wind facilities, particularly since these major investments were justified in part based on the ability of the project to provide economic benefits to Wyoming ratepayers. Accordingly, in **Confidential WIEC Exhibit No. 200.12**, I performed an analysis of the performance of RMP's wind resources relative to the "P50" production assumptions that were made at the time that RMP made the decision to make these investments. The P50 production estimates are the median expected output from the wind facilities and were provided in response to WIEC Data Request 5.2.

Q. WHAT DID YOUR ANALYSIS SHOW?

A. It showed that, on average, RMP's wind facilities under produced by approximately 3.2% or 645,485 MWh. Of the 17 wind plants analyzed, 14 under produced their P50 production estimate and only 3 produced at, or above, the P50 production estimate. This underperformance relative to the P50 production assumption cost ratepayers significantly in the Deferral Period. Considering that the average cost of power at Palo Verde and Mid-Columbia was approximately $97.55/MWh and $81.77/MWh, respectively, in the Deferral Period, the under production of RMP's wind facilities cost ratepayers $59,886,800 on a Total-Company basis. On a Wyoming-allocated basis, the cost of underperforming wind was approximately $9,267,347. Considering the major increase to NPC experienced in the Deferral Period, this under production runs counter to the benefits that RMP promised when it requested that the Commission approve these investments in the 2020 GRC.

Q. IS IT POSSIBLE TO FULLY EVALUATE RMP'S WIND FACILITY PERFORMANCE IN A SINGLE ECAM?

A. While the under production in 2023 was significant, it is difficult to form conclusions about the production of RMP's wind facilities by looking at a single year in isolation. The proper way to consider the efficacy of RMP's wind production would be to evaluate it over a number of years, such as a three-year period. Based on the way the ECAM operates, however, such an analysis is not possible. The ECAM only considers one year, and it would not be possible to address under production in this year's ECAM, if it was later found that the wind facilities are consistently under producing their P50 estimates.

Q. HOW DO YOU RECOMMEND RESOLVING THIS ISSUE IN THIS ECAM?

A. My recommendation is to adopt a mechanism that removes the cost associated with wind underproduction in this proceeding. Instead of disallowing the cost, however, I recommend holding the amount in a reserve and allowing RMP to incorporate it into a later year's ECAM proceeding, but only to the extent wind overproduces in the year. This way, the wind under production will serve effectively as a balancing account to ensure that ratepayers are not perpetually paying additional costs due to the failure of RMP's wind facilities to perform at the levels that were represented when the investments were made.

Q. DO YOU RECOMMEND A FULL PRUDENCE EVALUATION OF WIND PRODUCTION TAKE PLACE IN A LATER ECAM PROCEEDING?

A. Yes. At the end of three years, in the 2025 ECAM, I recommend a holistic prudence review of RMP's wind performance to determine how to handle any remaining balances held in reserve.

Q. WILL THIS RECOMMENDATION HELP TO SMOOTH OUT ECAM RECOVERY?

A. Yes. This recommendation will have the added benefit of reducing ECAM recovery in years when actual NPC is higher and wind underperforms and increasing ECAM recovery in years when actual NPC is lower and wind overperforms.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION

A. Putting the cost of wind underproduction into a reserve for later recovery in a future ECAM results in a $7,712,741 reduction to the ECAM balance inclusive of 80% sharing and interest.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER TO INCREASE CURRENT RATES BY $50.3 MILLION (7.6 PERCENT) TO RECOVER DEFERRED NET POWER COSTS UNDER TARIFF SCHEDULE 95 ENERGY COST ADJUSTMENT MECHANISM AND TO DECREASE CURRENT RATES BY $1.5 MILLION (0.2 PERCENT) UNDER TARIFF SCHEDULE 93, REC AND SO2 REVENUE ADJUSTMENT MECHANISM	DOCKET NO. 20000-642-EM-23 (Record No. 17279)

AFFIDAVIT, OATH AND VERIFICATION

STATE OF NEVADA)
) SS:
COUNTY OF CLARK)

Bradley G. Mullins, being first duly sworn, on his oath states:

1. My name is Bradley G. Mullins. I am a Principal Consultant in the firm of MW Analytics. I have been retained by the Wyoming Industrial Energy Consumers to testify in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony and Exhibits, which has been prepared in written form for introduction into evidence in Docket No. 20000-642-EM-23.

3. I hereby swear and affirm that my answers contained in this testimony are true and correct.

Bradley G Mullins

Bradley G. Mullins
MW Analytics
Tietotie 2, Suite 208
Oulunsalo, Finland FI 90460

Subscribed and sworn to before me by Bradley G. Mullins this 6th day of September, 2023.

Notary Public
Commission #: 18-2817-1

William E Bumphrey
NOTARY PUBLIC
STATE OF NEVADA
Appt. No. 18-2817-1
Expires July 10, 2026

My Commission Expires: 07/10/2026

Notarized Remotely Online via audio/video communications.

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