REDACTED
Docket No. 20000-633-ER-23
Witness: Ramon J. Mitchell

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Ramon J. Mitchell

September 2023

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ATTACHED EXHIBITS

Exhibit 10.8 – Effects of Ambient Temperature on Gas Generation Output

Exhibit 10.9 – Effects of Ambient Temperature on Coal Generation Output

Exhibit 10.10 – Supplemental Direct Testimony Aurora Version

Q. Are you the same Ramon J. Mitchell who filed direct ("initial filing") and supplemental direct testimony ("NPC Update") in this proceeding on behalf of PacifiCorp, d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company")?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. I respond to the direct testimony of Colin T. Fitzhenry, filed on behalf of the Wyoming Office of Consumer Advocate ("WOCA"), Kevin C. Higgins, and Bradley G. Mullins, filed on behalf of the Wyoming Industrial Energy Consumers ("WIEC"), and Ronald J. Binz, filed on behalf of the Sierra Club.

Q. Please summarize your testimony.

A. I demonstrate the reasonableness of the Company's net power costs ("NPC") and Energy Cost Adjustment Mechanism ("ECAM") sharing band elimination proposal in this 2023 general rate case ("GRC") and respond to the testimony from the parties through the following points:

- Calendar year 2023 NPC actuals are trending towards $2.610 billion and considering the new operational changes in 2024 that are not in 2023, the Company's NPC proposal is reasonable, if not under-stated. This is discussed in Section II.
- There are rather serious issues surrounding WIEC's usage and understanding of both NPC modeling in general and Aurora specifically. Various NPC adjustments have been misrepresented and WIEC's workpapers are heavily erroneous. This is first discussed in Section III and then throughout the remainder of my testimony.

- In aggregate, input commodity—electricity, gas and coal—prices over summer and winter peak periods in 2024 are unfavorable compared to both 2021 and 2022; and in 2024 there is substantially limited generation availability due to new operating and policy conditions. This limited generation availability—all else equal—result in a higher cost of market purchases and increased volume of market purchases to provide replacement energy. Furthermore, when comparing coal or gas price changes it is necessary to use prices at the location of the Company's plants. This is discussed in Section IV.
- Those changes in the July NPC Update which WIEC labels as new modeling techniques are in fact corrections; and those changes which are actually new modeling techniques are conveniently ignored by WIEC. Per WIEC's suggestion, removing new modeling techniques from the July NPC Update results in a substantial increase to NPC, an increase of up to $219 million total-Company. This increase is inappropriate. Furthermore, WIEC completely misses the mark on how NPC impacts in an NPC log (change log) work. This is discussed in Section V.
- Company witness Mr. James C. Owen details the Company's current coal supply limitations and the state of regional coal industries. Separately, the Company's modeling of the impact of coal supply limitations in Aurora is accurate. Furthermore, the associated NPC impact presented in the July NPC Update is accurate and WIEC demonstrates a lack of understanding on how to model with the Aurora software. This is discussed in Section VI and Section XIII.
- The Ozone Transport Rule ("OTR") is proposed to be removed from the NPC forecast due to a recent litigation outcome. The NPC impact of this change is a

decrease of $22 million total-Company, relative to the July NPC Update. This is discussed in Section VII.

- Wyoming customers are receiving benefits from Chehalis, even with greenhouse gas ("GHG") compliance, to the tune of $133 million total-Company. This is discussed in Section VIII.
- Any discussion on the interaction of the Day-Ahead and Real-Time ("DA/RT") adjustment and the Extended Day Ahead Market ("EDAM") is premature until the EDAM starts. As of August 2023, the EDAM is now scheduled to start in 2026. Furthermore, the DA/RT price component and the DA/RT volume component are both separately necessary to account for real-world-trading price inefficiencies and volume inefficiencies, respectively. Each component serves a separate function. Furthermore, the DA/RT volume component was clearly producing erroneous results in the initial filing and the Company's elimination of the error is therefore a correction. This is discussed in Section IX.
- WIEC's analyses on market capacity limits is erroneous and, when corrected, support the Company's position that the average of averages method is appropriate. This is discussed in Section X.
- Certain coal and gas plants' performance decreases during high ambient temperatures and this is an engineering fact. WOCA's analysis double counts generation capacity and erroneously shows benefits that do not exist. This is discussed in Section XI.
- Approximately 700 megawatts ("MW") of capacity at Jim Bridger is converting to gas-fired operations at the end of 2023 and this conversion requires a three to five

month outage in 2024. This is known and measurable. WOCA's proposal is reasonable. This is discussed in Section XII.

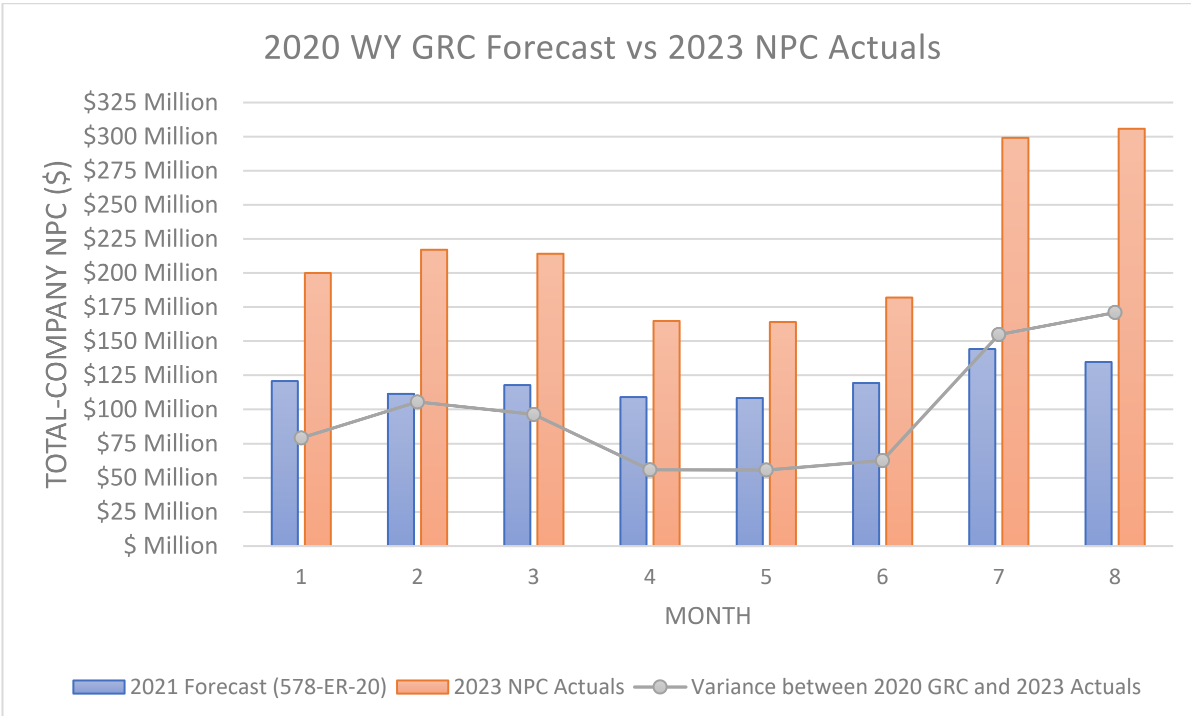
- WIEC has erroneously calculated the NPC impact of holding North American Electric Reliability Corporation ("NERC")-mandated reserves for control (balancing) area reliability. Regardless, WIEC's proposal is *first* reckless as it attempts to incent the Company to save on power costs by sacrificing reliable and safe electric service for Wyoming customers; and *second,* founded on a misunderstanding of cost-based ratemaking. This is discussed in Section XIV.
- Outside of Wyoming-specific operations, the energy cost adjustment mechanism ("ECAM") sharing band does not incentivize the Company to control costs. Consequently, of the "four-leg", stable, as-*designed* incentives of the ECAM, only two "legs" actually function. Within this context, the "two-leg" remainder of the ECAM sharing band is no longer stable, no longer operating as designed, and should be eliminated in favor of judicious prudency review which is already underway in the 2023 ECAM and will become even more manageable when the Company automates most transactions under the EDAM. This is discussed in Section XV.

II. NPC UNDER-FORECAST IN CURRENT RATES

Q. How do the *year-to-date* 2023 NPC actuals compare to the NPC forecast that is currently in base rates?

A. Figure NPC-1 demonstrates the variance between preliminary actual 2023 NPC incurred *year-to-date,* as compared to the forecast of NPC in the 2020 GRC and currently effective in base rates. On a preliminary basis, the total *year-to-date*[1] NPC variance is an under-forecast of $781 million dollars total-Company.

Figure NPC-1



Q. What is the significance of your emphasis on "year-to-date"?

A. These NPC under-forecast values that sum to $781 million total-Company are only for eight months of the year, from January 2023 to August 2023. Each individual month demonstrates a NPC under-forecast and no single month shows the 2020 GRC forecast at or above the actual NPC incurred. With information known to date, it is impossible that the next four months will manage to reverse this NPC under-forecast.

Q. How are these comparisons and associated NPC under-forecast relevant to this GRC NPC proposal?

A. The goal of the NPC forecast is to achieve an *accurate* forecast of the Company's

[1] January 2023 to August 2023.

power costs for the upcoming year.[2] As we strive to produce an accurate NPC forecast for 2024, it is important to note that: (1) the 2020 GRC's NPC forecast was an under-forecast of $283 million total-Company, relative to 2021 actuals;[3] (2) the 2020 GRC's NPC forecast was an under-forecast of $610 million total-Company, relative to 2022 actuals;[4] (3) the 2020 GRC's NPC forecast is shaping up to be an under-forecast of $1.178 billion total-Company, relative to load ratio extrapolated 2023 actuals; (4) new to 2024, and not present in 2023, is a three to five month outage of approximately 700 MW of dispatchable capacity at the Jim Bridger plant to accommodate a required gas conversion;[5] (5) new to 2024, and not present in 2023, is the required deconstruction of up to 180 MW of dispatchable capacity from hydroelectric projects along the Klamath River;[6] and (6) aggregate market prices, inclusive of coal supply prices and coal supply constraints in 2023 as compared to 2024 as of the June 30 official forward price curve ("OFPC") are relatively unchanged, and all are substantially higher than the level assumed in the 2020 GRC.

Load ratio extrapolation on the eight months of actual 2023 NPC indicates that calendar year 2023 NPC would be approximately $2.610 billion, total-Company, and the Company's 2024 NPC forecast is $2.518 billion, total-Company.[7] Considering the operational changes in 2024 discussed above, the 2023 NPC trend, and the robust

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[2] *See, In the Matter of the Application of Rocky Mountain Power for Authority to Implement an Energy Cost Adjustment Mechanism*, Docket No. 20000-368-EA-10 (Record No. 12477), Memorandum Opinion, Findings and Order at 23 (Feb. 4, 2011) ("The Commission finds and concludes that the ECAM should be structured to provide incentives to the Company for four purposes: . . . [ii] to encourage the accuracy of modeling supporting the forecasts[.]"). !
[3] Direct Testimony of Ramon J. Mitchell at 10 (RMP Exhibit 10.0).
[4] *Id*.
[5] *Id.*, at 18-19.
[6] *Id.*, at 19.
[7] As explained below in Section VII, the OTR is proposed to be removed from the NPC forecast.

modeling performed by the Company, the 2024 forecast is reasonable, if not under-stated.

Q. Are parties aware that the 2023 NPC incurred year-to-date are of such magnitude?

A. Yes. The Company files quarterly actual NPC reports on the Wyoming Public Service Commission's ("Commission") docket management system and also directly provides the report to WIEC and WOCA.

III. THE AURORA PRODUCTION COST MODEL

Q. WIEC testifies extensively regarding its understanding of the Aurora production cost model used by the Company to forecast NPC in this case.[8] As an initial matter, how do you respond to WIEC's general testimony related to Aurora?

A. WIEC witness Mr. Mullins' characterization of Aurora is based on a fundamental misunderstanding of both NPC modeling in general and Aurora specifically. Several of WIEC's recommended adjustments largely result from WIEC's use of incorrect Aurora modeling inputs (*e.g.*, coal costs), incorrect characterization of the NPC model (*e.g.*, Aurora model environment and DA/RT adjustment), or incorrect interpretation of modeling results (*e.g.*, NPC changes or impacts), as discussed in more detail throughout my testimony.

[8] *See, e.g.,* Direct Testimony of Bradley G. Mullins at 10 (WIEC Exhibit No. 202).

Q. WIEC claims that the Company's old production cost model used an approach referred to as "least cost dispatch," which produced a more optimized system dispatch relative to the "merit order" dispatch that WIEC believes is used by the Company's current model, Aurora.[9] How do you respond?

A. WIEC's attempt to distinguish the Company's old model from Aurora does not withstand scrutiny. WIEC claims that a model that uses a "**least cost**" dispatch approach produces more optimal results than a model that uses a "**merit order**" dispatch approach.[10] Based on this claim, WIEC states that the Company's old production cost model, the Generation and Regulation Initiative Decision Tools ("GRID") "produced a more optimized system dispatch" than the Company's current model, Aurora.[11] WIEC then uses this claim to justify recommended changes to multiple modeling techniques.

The fatal flaw with WIEC's argument is that "**least cost** dispatch" means the exact same thing as "**merit order** dispatch." Contrary to WIEC's claim, Aurora employs more advanced mathematical techniques to forecast NPC and is over-optimized relative to GRID. Mr. Mullins previously acknowledged Aurora's superiority in 2021 testimony filed with the Oregon Public Utility Commission ("OPUC"), where he testified that the "AURORA model contains a more sophisticated commitment and dispatch logic than the GRID model[.]"[12]

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[9] Direct Testimony of Bradley G. Mullins at 10 (WIEC Exhibit No. 202).
[10] *Id*.
[11] *Id*.
[12] *In the Matter of PacifiCorp dba Pacific Power 2022 Transition Adjustment Mechanism*, OPUC Docket No. UE 390, Rebuttal and Cross-Answering Testimony of Bradley G. Mullins at 4 (AWEC/200) (Aug. 26, 2021).

Q. Please define these concepts of "least cost dispatch" and "merit order dispatch".

A. Least cost dispatch "*implies utilizing the generating unit with the lowest variable cost […] to ramp up to serve increases in loads.*"[13] Merit order dispatch "*determine[s] the order in which different sources of electricity should be used to meet demand. It is based on the marginal cost of each source, with the lowest-cost sources used first.*"[14]

As can be immediately inferred, these two terms are concepts—not specific mathematical formulations—and they both mean the same thing. WIEC's use of different words to describe the same modeling concept used by GRID and Aurora does not create a meaningful distinction between the two models.

Q. How then is Aurora different from GRID?

A. GRID had a number of limitations, which were primarily a lack of co-optimization between energy and ancillary services, unit commitment logic that was decades out of date, an inability to constrain fuel usage on thermal resources, and no concept of storage resources or emissions. Aurora improves on all these aspects. Aurora calculates a transmission-constrained, **least-cost** dispatch using effectively simultaneous unit commitment and economic dispatch processes, which are driven by an advanced hourly mixed integer program and linear program, respectively. Furthermore, Aurora co-optimizes both energy and ancillary services as opposed to the inefficient sequential optimization employed by GRID, and additionally, allows for the application of a myriad of constraints inclusive of ramp rate constraints, emissions constraints, and fuel constraints, all of which were either not present in GRID or of limited functionality.

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[13] Energy KnowledgeBase, *Economic Dispatch* (available at https://energyknowledgebase.com/topics/economic-dispatch.asp) (last visited Sept. 18, 2023).

[14] Nano Energies, *Merit Order* (available at https://nanoenergies.eu/knowledge-base/merit-order) (last visited Sept. 18, 2023).

Q. As foundational support for its modeling recommendations, WIEC claims that Aurora "produces more relaxed system dispatch, and therefore, the concerns about over optimization are not necessarily as pertinent[.]"[15] In light of the information presented above, is this an accurate statement?

A. No. Aurora employs more advanced mathematical techniques to forecast NPC and therefore the results from Aurora are over-optimized relative to GRID.

WIEC does not demonstrate a solid understanding of what Aurora is, how it functions, or how to use the software. I discuss these issues in more detail below, in multiple sections of my testimony.

Q. WIEC also claims that Aurora produces different results if run on different computers.[16] Is this true?

A. No. If Aurora is properly configured and competently run, the choice of computer will have no impact on the output. Indeed, while WIEC claims different "computer architecture" produces different results, WIEC produced no evidence explaining why that would be the case for a state-of-the-art model like Aurora; WIEC produced no evidence that the "computer architecture" used by Mr. Mullins was different from the "computer architecture" used by the Company; and WIEC produced no evidence that the simple fact its modeling produced a lower NPC forecast means that the lower forecast is more accurate.

Q. Please elaborate.

A. There are only four scenarios under which Aurora, if not properly configured, may produce results that are not reproducible on a second computer.

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[15] Direct Testimony of Bradley G. Mullins at 10 (WIEC Exhibit No. 202).
[16] *Id.,* at 29.

(1) The second computer is running on a different version of Aurora.

(2) The "Max Solve Time" setting is set too low.

(3) The software is enabled to use dynamic parallel processing.

(4) The software is tuned for performance specific to a particular machine.

The Company has different computers with different architectures and the Company's Aurora projects: (1) produce the same results when they use the same version of Aurora; and (2) are appropriately configured to avoid the pitfalls of scenarios 2, 3 and 4.

Scenarios 2 and 3 are outlined in the Aurora help file, Scenario 1 is basic modeling knowledge, and Scenarios 2, 3 and 4 requires the operator to intentionally change the settings from those embedded in the model that the Company provides.

Q. Of these four scenarios, which one has WIEC violated?

A. Scenario 1. WIEC did not use the same version of Aurora as the Company. This is the most basic of operator errors and in discovery, the Company made clear the version of Aurora that was used by the Company (14.2.1059), yet WIEC chose to use an older version (14.2.1052).[17] Any differences between the Company's modeling and WIEC's is therefore attributable to the different—and older—version WIEC chose to use, not because of differences in computer architecture or differences in rounding and randomization,[18] which have no supporting evidence in the Aurora documentation to support these claims.

[17] RMP's 1st supplemental response to WIEC Data Request 1.4 and WIEC's response to RMP Data Request 5.1, included as RMP Exhibit 10.10.
[18] Direct Testimony of Bradley G. Mullins at 28 (WIEC Exhibit No. 202).

Q. WIEC claims that because Mr. Mullins' "computer architecture" produces a lower cost "driven by slightly more efficient plant dispatch" than Rocky Mountain Power's modeling, his "model runs can be viewed as producing a more accurate forecast."[19] Is that true?

A. No. To further understand the flaws in Mr. Mullins' reasoning, it is important to outline his evolving claims around Aurora's modeling on his computer as compared to the Company. In testimony filed on June 23, 2023, with the OPUC, Mr. Mullins pointed out that, "Energy Exemplar provides periodic updates to the AURORA model every few months" and according to Mr. Mullins, those "updates generally include changes and improvements to the modeling environment and the model's algorithms."[20] In that June 23rd testimony, Mr. Mullins attributed the differences between his modeling and the Company's modeling to the fact that Mr. Mullins was using a newer version of Aurora.[21] Then, after the Company updated its version of Aurora to a newer version than Mr. Mullins, in Oregon testimony filed on August 16, 2023, Mr. Mullins reversed course and claimed that the version of Aurora used in the modeling is immaterial and the differences between his own modeling and the Company's resulted from his undefined difference in "computer architecture."[22] Mr. Mullins' evolving and contradictory claims about Aurora undermine the credibility of his testimony. The fact is that any differences between Mr. Mullins' and the Company's modeling are attributed to different versions of Aurora, not differences in "computer architecture."

[19] *Id.*, at 29.
[20] *In the Matter of PacifiCorp, dba Pacific Power, 2024 Transition Adjustment Mechanism*, OPUC Docket No. UE 420, Opening Testimony of Bradley G. Mullins at 3 (AWEC/100) (June 23, 2023).
[21] OPUC Docket No. UE 420, Opening Testimony of Bradley G. Mullins at 3 (AWEC/100).
[22] OPUC Docket No. UE 420, Rebuttal Testimony of Bradley G. Mullins at 39-40 (AWEC/200) (Aug. 16, 2023).

Because Mr. Mullins agrees that more recent versions of Aurora include improvements over older versions, there is no basis to conclude that his reliance on an older version produces a more accurate forecast.

Q. Are there any issues with how WIEC presented its recommended NPC adjustments in its testimony?

A. Yes. WIEC presents its recommended test period NPC forecast in Table BGM-1.[23] That table, however, does not show the true cost impact of any one change recommended by WIEC. Although unstated in the testimony, WIEC's adjustments were performed sequentially, meaning, for example, WIEC first changed the coal costs, then layered on top of the new coal costs the DA/RT adjustment changes, then layered on top the market cap changes, etc. By using a sequential change log, the NPC impact of each individual modeling change is dependent on the position of the change in the log. In testimony filed earlier this year with the OPUC, Mr. Mullins acknowledged that a sequential change log skews the NPC impacts based solely on the order in which the calculations were performed.[24] Because Mr. Mullins' Table BGM-1 uses sequential changes, it skews the results and is misleading.

Q. Please provide an example of how the order of the change log skews the NPC impacts.

A. Consider a scenario where the first change is an update to the OFPC, that update might increase NPC by $100 million. If the second sequential change is an update to short-term firm power contracts, then that update might be a NPC increase of $50 million for

[23] Direct Testimony of Bradley G. Mullins at 7 (WIEC Exhibit No. 202).
[24] *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, OPUC Docket No. UE 416, Opening Testimony of Bradley G. Mullins at 36 (AWEC/100) (May 24, 2023).

a combined total of $150 million increase to NPC. But, if the order of the line-items were reversed one could end up with a scenario where the NPC impact of the OFPC as the second step is now $80 million and the NPC impact of updated short-term firm power contracts as the first step is now $70 million for a combined total of $150 million increase to NPC. By making the changes sequential, the change log would distort the impact of each individual change because the impact of each individual change is dependent both on the changed variable and the relative position of that changed variable in the change log.

Q. How has the Company avoided this pitfall of providing skewed and misleading NPC impacts?

A. When the Company presented its NPC change log in the July NPC Update, each line-item was a one-off modeling sensitivity that assessed the isolated impact of including or removing that one change in the NPC proposal.[25] In this manner, the reader is able to understand what would happen to the NPC proposal if any one change were included or removed. No change was dependent on the modeling results of another change and each NPC impact from each change provides the true cost impact of that change. Had the Company used a sequential change log, the Company could increase or decrease the NPC impact as presented to the reader based on strategic positioning of the line-item within the change log. This type of sequential change log is what WIEC has presented in its Table BGM-1.

[25] Net Power Cost List of Corrections and Updates at 2 (RMP Exhibit 10.6).

Q. Have you corrected WIEC's Table BGM-1 to show a more accurate, or non-skewed, valuation of each of WIEC's individual NPC adjustments?

A. Yes. In Figure AURORA-1 below I re-present WIEC's Table BGM-1 and in Figure AURORA-2 below, I used WIEC's workpapers and WIEC's Aurora project[26] to recreate the version of WIEC's change log that shows the true cost impact of any one change, by modeling each change as a one-off sensitivity (an isolated NPC scenario). Note the large discrepancies in multiple line items between how WIEC portrays the NPC impacts in testimony as compared to the true cost impact of each one change.

Figure AURORA-1 – WIEC's Tabulated NPC Impacts

		Total Company	Wyoming Allocated
1	**RMP July Update NPC Forecast**	**2,540,351,036**	**357,800,000**
2	**Modeling Differences:**		
3	Initial Filing Coal Costs	(115,225,600)	(15,843,014)
4	AURORA Model Environment	(2,094,140)	(287,935)
5	Washington CCA	(69,523,712)	(9,559,205)
6	DA/RT: July Update Method Change	(80,199,295)	(11,027,051)
7	DA/RT Method Simplification	(17,141,121)	(2,356,829)
8	Market Caps - Liquid Markets	(20,974,080)	(2,883,844)
9	Market Caps - 95th Percentile	(17,091,156)	(2,349,959)
10	Ozone Transport Rule	(17,961,132)	(2,469,577)
11	Non-Native Reserves	(210,694,263)	(28,969,536)
12	**Total Modeling Differences**	**(550,904,499)**	**(75,746,951)**
13	**Mullins NPC Forecast**	**1,989,446,537**	**282,053,049**

[26] After correcting for WIEC's various modeling errors described in this testimony.

Figure AURORA-2 – Updated – True Cost Impact of Any One Change

		Total Company	Wyoming Allocated
1	**RMP July Update NPC Forecast**	**2,540,351,036**	**357,800,000**
2	**Modeling Differences:**		
3	Initial Filing Coal Costs[1]	-	-
4	AURORA Model Environment	-	-
5	Washington CCA	(72,373,205)	(9,950,998)
6	DA/RT: July Update Correction[2]	(65,812,659)	(9,048,952)
7	DA/RT Method Simplification	(87,151,495)	(11,982,948)
8	Market Caps - Liquid Markets	(18,708,081)	(2,572,279)
9	Market Caps - 95th Percentile	(30,424,509)	(4,183,236)
10	Ozone Transport Rule	(22,393,545)	(3,079,014)
11	Non-Native Reserves[1]	(125,392,238)	(17,240,882)
12	**Total Modeling Differences**	**(422,255,734)**	**(58,058,310)**
13	**Mullins NPC Forecast - Simple Addition[3]**	**2,118,095,302**	**291,228,808**
14	**System Balancing Impact of Adjustments[4]**	**93,320,286**	**12,831,130**
15	**Mullins NPC Forecast - Actual Impact**	**2,211,415,588**	**304,059,938**

[1] As explained in this testimony, this is a WIEC error.

[2] Relabeled to reflect status as correction.

[3] WIEC claims this would be the total NPC Impact.

[4] Per WIEC's logic, **WIEC is forcing in a $93 million plug to NPC** for unexplained variance to force its request to match the final model and WIEC is increasing customer rates with this plug.

Note also that when the cost impacts are presented correctly, there is a "system balancing impact of adjustments" (footnote 4 in Figure AURORA-2 above), which I discuss below in Section V.

IV. MARKET PRICES

A. Background

Q. What market prices were used to set NPC in the current base rates approved in the 2020 GRC?

A. The test period for the 2020 GRC was calendar year 2021, therefore the market prices used to set the NPC baseline in that case were 2021 forecast market prices that were known in June 2020.

Q. What market prices were used to set NPC in the proposed rates in this proceeding?

A. The 2024 forecast market prices known in June 2023.

Q. Have power sector electricity prices, coal prices and natural gas prices increased between the 2021 and 2024 price forecasts?

A. Yes. Based on the June 30 OFPC used in the July NPC update of my supplemental direct testimony ("NPC Update"),[27] from the 2021 forecast to the 2024 forecast:

(1) Pacific Northwest summer and winter peak electricity prices increased by an annual average of 263 percent and Desert Southwest summer and winter peak electricity prices increased by an annual average of 201 percent;

(2) Company coal prices increased by an annual average of 29 percent;

(3) Coal supply constraints increased NPC, primarily through a 32 percent reduction in coal generation;

(4) Pacific Northwest summer and winter natural gas prices increased by 103 percent and Rocky Mountain region summer and winter natural gas prices

[27] Updated NPC Study (RMP Exhibit 10.5).

increased by 89 percent; and

(5) On an overall annual average basis, Pacific Northwest electricity prices and gas prices increased by 232 percent and 85 percent respectively. Desert Southwest electricity prices and gas prices increased by 175 percent and 74 percent respectively.

This information is tabulated below in Table PRICE-1.

Table PRICE-1

Commodity	Pacific Northwest (Summer and Winter)	Desert Southwest / Rocky Mountain (Summer and Winter)
Electricity Price Increase	263%	201%
Gas Price Increase	102%	89%
Coal Price Increase		29%

Q. Why are higher summer and winter prices particularly critical when comparing prices?

A. Summer and winter peak periods are periods of high customer demand and stressed system conditions and higher power prices in those periods will produce NPC that are substantially higher than the relatively slight decreases in NPC resulting from low prices in spring and fall months, which have light load and relatively mild system conditions.

B. Reply to WOCA

Q. Please describe WOCA's issue regarding the Company's forward price curves.

A. WOCA's testimony shows annual average natural gas prices increasing by 47.5 percent,[28] which is materially less than the Company's annual average natural gas price

[28] Direct Testimony of Colin T. Fitzhenry at 10, Table 3 (WOCA Exhibit No. 603).

increases of between 74 percent and 85 percent, presented above.

Q. How do you respond to this issue?

A. WOCA relied on prices from the United States ("U.S.") Energy Information Administration's ("EIA") website. For natural gas prices, the EIA data provides average natural gas prices derived from delivery points across the 50 states in the U.S. However, the Company does not take delivery across the 50 states. The Company takes natural gas delivery primarily at Opal in Wyoming, Sumas along the Canada/Washington border and Stanfield in Eastern Oregon.

The Company's natural gas delivery prices are the forward market prices from those delivery points. Average U.S. natural gas prices are not relevant here.

Q. WOCA also points to coal prices increasing by 24.5 percent.[29] Why is this increase different from the Company's number of 29 percent?

A. Similar to the data used by WOCA for natural gas, WOCA used EIA coal price averages from across the 50 states. The Company does not take coal delivery from across the nation, the Company primarily takes delivery from state-specific suppliers and has long-term bilateral coal supply agreements with those suppliers. Average U.S. coal prices are not relevant here.

Q. WOCA claims that the Company has "proposed OFPCs for natural gas" and that they do not "accurately reflect the current natural gas forward market prices."[30] How do you respond?

A. As an initial matter, the Company does not have "proposed OFPCs for natural gas." This implies that the Company itself calculates or otherwise forecasts natural gas

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[29] *Id.*
[30] *Id.*, at 11.

market prices. The Company's OFPC for natural gas are the **actual** natural gas forward market prices.

Q. How does WOCA show lower natural gas forward market prices than the Company if both WOCA's prices and the Company's prices are actual natural gas forward market prices?

A. WOCA's assertions includes an assumption that the Company receives physical delivery of natural gas from Henry Hub in Louisiana and WOCA shows Henry Hub natural gas prices.[31] However, the Company does not take physical gas delivery in that state. The Company takes natural gas delivery primarily at Opal in Wyoming, Sumas along the Canada/Washington border and Stanfield in Eastern Oregon. Henry Hub natural gas prices are not the prices for physical delivery to the Company's gas plants.

Q. WOCA "adjusted the monthly fuel prices for the test year period for Chehalis, Lake Side, Gadsby, Naughton, Hermiston, and Currant Creek to reflect the decrease in the [New York Mercantile Exchange] Henry Hub price" and found a decrease in NPC of $42 million total-Company.[32] Is this adjustment relevant to the Company's gas plant operations?

A. No. Lake Side, Gadsby, Naughton, and Currant Creek are priced relative to Opal,[33] Chehalis is priced relative to Sumas,[34] and Hermiston is priced relative to Stanfield.[35] The Company has no natural gas pipeline transportation rights to move natural gas from

[31] *Id.*
[32] *Id.*
[33] Lake Side, Gadsby, and Currant Creek are in Utah. Naughton is in Wyoming.
[34] Chehalis is in Washington.
[35] Hermiston is in Oregon.

Louisiana (Henry Hub) to Wyoming, Utah, Washington or Oregon, therefore WOCA's adjustment is invalid and operationally infeasible.

Prices at various natural gas delivery points depend on regional market conditions, transportation costs and available pipeline capacity between locations. The price of natural gas in Louisiana is not comparable to the price of natural gas at the Company's gas plants. This is similar in concept to how a vehicle driver in Wyoming cannot fill up their vehicle's gas tank at Louisiana gas prices, but instead takes the gas price at their local pump. For example, at the time of writing this testimony, the average gas (ethanol) price in Wyoming was 16 percent higher than the average gas price in Louisiana.[36]

Q. In light of these facts, is WOCA's adjustment to NPC accurate?

A. No. The natural gas prices used by the Company are the real forward market prices as of the June 30 OFPC, and absent an OFPC update, they are valid for my supplemental direct testimony. WOCA's adjustment to NPC is inaccurate.

C. Reply to WIEC

Q. WIEC claims that "[r]elative to 2022 [market] prices have declined materially" and uses this claim to assert that 2024 NPC should be lower than 2022 NPC.[37] How do you respond?

A. WIEC's testimony on this point is misleading for several reasons. First, WIEC presents Figure BGM-2 showing Mid-Columbia ("Mid-C") and Desert Southwest electricity (power) prices and Sumas and Opal gas prices and then points to a single price—Sumas

[36] Am. Auto. Ass'n, *State Gas Price Averages* (available at https://gasprices.aaa.com/state-gas-price-averages/) (calculated based on data available on September 6th).
[37] Direct Testimony of Bradley G. Mullins at 13 (WIEC Exhibit No. 202).

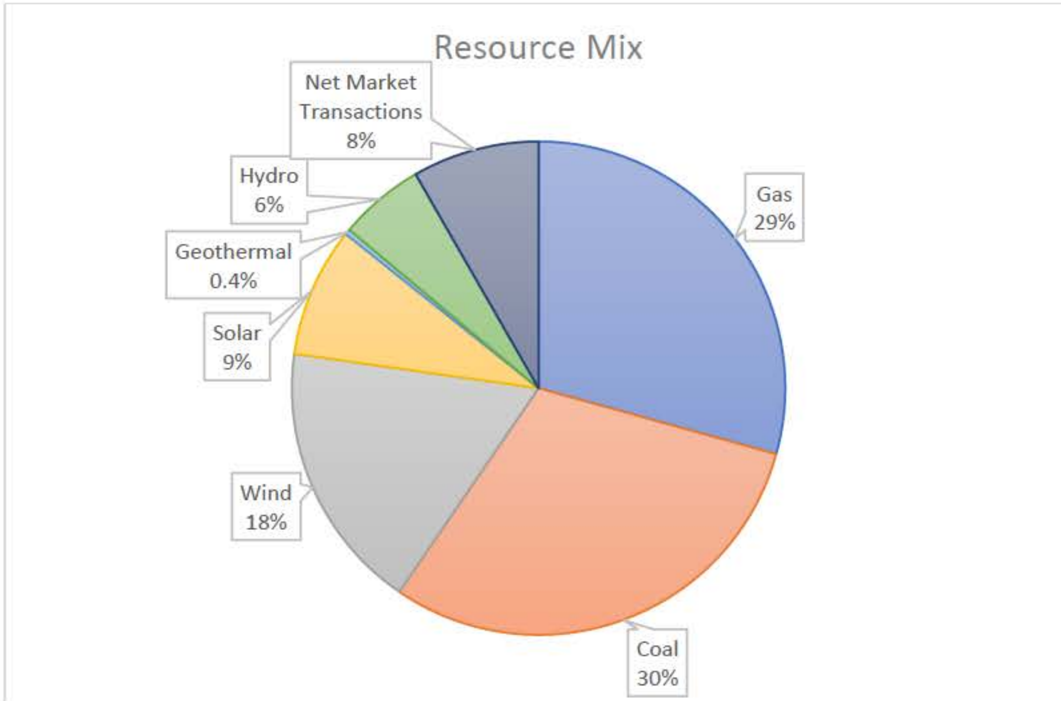
gas—that it is 20 percent lower than 2022 levels. However, evaluating WIEC's Figure BGM-2 in its entirety shows that on average: (1) summer power prices are **higher** in 2024 relative to 2022; (2) winter power and natural gas prices are **higher** in 2024 relative to 2022, with the exception of December 2022; (3) spring power prices are **lower** in 2024 relative to 2022; and (4) fall power prices are **lower** in 2024 relative to 2022.

As mentioned above, summer and winter peak periods are periods of high customer demand and stressed system conditions and higher power prices in those periods will produce NPC that are substantially higher than the relatively slight decreases in NPC resulting from low prices in spring and fall months, which have light load and relatively mild system conditions.

Q. Are there any other ways that WIEC's testimony misleadingly compares 2022 and 2024 data to suggest NPC should be lower?

A. Yes. WIEC ignores coal prices entirely. This omission is particularly egregious because coal serves the largest portion (30 percent) of 2024 forecast customer load and coal prices have increased by 30 percent from 2022 to 2024. Company witness Mr. Owen expands on the Company's coal situation in more detail. Figure PRICE-1 shows the Company's 2024 resource mix on a megawatt-hour ("MWh") basis as of the NPC Update.

Figure PRICE-1



Q. Did WIEC's comparison of 2022 to 2024 ignore any other important system changes?

A. Yes. WIEC fails to consider—and did not dispute—the NPC impact resulting from limited generation availability due to new operating and policy conditions such as coal supply limitations,[38] the OTR,[39] the Jim Bridger gas conversion and associated outage, the removal of the Klamath dams, and the Washington Cap and Invest Program,[40] all of which—all else equal—increase the 2024 NPC forecast.

Additionally, WIEC makes an unsupported claim of "large increases in zero fuel costs renewable resources coming online in the test period"[41] but, fails to identify:

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[38] Supplemental Direct Testimony of Ramon J. Mitchell at 9 (RMP Exhibit 10.4).
[39] The OTR is proposed to be removed from the NPC forecast, but is mentioned in testimony here since it was included in the NPC Update and parties' direct testimonies include analyses based on that inclusion.
[40] Direct Testimony of Ramon J. Mitchell at 11-12 (RMP Exhibit 10.0).
[41] Direct Testimony of Bradley G. Mullins at 13 (WIEC Exhibit No. 202).

(1) what specific technology type of resources these are; (2) how large (or small) they are; (3) where they are; (4) what regional transmission limitations they face; (5) what their capacity factors are; or (6) which customers they serve.

Taken together, WIEC's misleading description of the data it provided, coupled with the data WIEC ignored, makes its comparison of 2022 to 2024 NPC incomplete and not credible.

Q. When examining the relevant data, what conclusions can the Commission draw from the price differences between 2022 and 2024?

A. Based on the June 30 OFPC used by the NPC Update, from 2022 to 2024:

(1) Pacific Northwest summer and winter peak power prices **increase** by an annual average of 36 percent and Desert Southwest summer and winter peak power prices **increase** by an annual average of 22 percent;

(2) Company coal prices **increase** by an annual average of 30 percent;

(3) Coal supply constraints **increase** NPC, primarily through a 31 percent reduction in coal generation;

(4) Pacific Northwest winter natural gas prices **increase** by 90 percent and Rocky Mountain region winter natural gas prices **increase** by 38 percent (both calculations excluding the anomalous December 2022 price excursion);[42] and

(5) The summer natural gas prices **decrease** by 53 percent in the Pacific Northwest and 57 percent in the Rocky Mountain region.

[42] The Company excluded the outlier data from December 2022 price because inclusion of that anomalous price spike skews the comparison of 2022 to 2024 data. However, in the interest of complete analysis for the record, from 2022 to 2024, December natural gas prices in the Pacific Northwest and in the Rocky Mountain region decreases by 74 percent and 79 percent respectively.

When the data is examined in its totality and in the context of the broader resource mix and operating changes discussed above (most particularly the reduction in coal supply and the increase in coal prices), and the Company's exposure to power market prices, it is evident that the unfavorable changes in summer and winter power price conditions, the unfavorable changes in winter natural gas conditions, and the unfavorable changes in year-round (inclusive of summer and winter) coal price *and* coal supply conditions far outweigh the favorable changes in summer and December natural gas conditions.

Q. Instead of changes in market prices, WIEC claims that the 2024 forecast of "net short-term purchases" is higher than 2022 because of increased costs of net short-term purchases that are "likely being caused in part by some of the modeling techniques […] such as the DA/RT [adjustment] and market cap modeling methods."[43] Do you agree?

A. No. As discussed above, increased market prices over peak periods and new operating and policy conditions are the significant contributors to increased NPC, contrary to WIEC's testimony.

Q. WIEC questions the increase in "net short-term purchases" in the 2024 NPC forecast given the increase in gas and renewable resource generation and therefore claims this increase in "net short-term purchases" is an unexpected result.[44] How do you respond?

A. WIEC claims that increased gas production and new renewable resource generation should have decreased net short-term purchase expense and that because this is not

[43] Direct Testimony of Bradley G. Mullins at 14-15 (WIEC Exhibit No. 202).
[44] *Id.*, at 15.

occurring, this further supports WIEC's claim that the 2024 NPC forecast is overstated.[45]

I rebut WIEC's misguided claims by discussing in Section IX(C) how WIEC's usage of "net" short-term purchases provides a misleading picture of the underlying short-term purchases separate from the underlying short-term sales before "netting." I also discuss how the changes in purchases across years are supported by the historical data and supported by new operating and policy conditions that the Company did not face in 2022, or years prior.

V. THE JULY NPC UPDATE

Q. WIEC states that it was their expectation that the NPC Update "would <u>not</u> include new modeling techniques" and therefore the Company's changes in the NPC Update titled "Contingency Reserves for Non-Owned Generation" and "Day-Ahead/Real-Time Volume Component" should be disallowed.[46] How do you respond?

A. The Company's changes in the NPC Update titled "Contingency Reserves for Non-Owned Generation" and "Day-Ahead/Real-Time Volume Component" are *corrections*,[47] not modeling changes and are therefore appropriate for the NPC Update, as discussed in more detail below in Section IX(C) and here below in Section V. WIEC is correct, however, that the Company included two new modeling techniques in the NPC Update—the "Ozone Transport Rule [nitrous oxide ("NOx")] Allowance Aggregation" and "Thermal Generation's Marginal Costs."[48] Notably, WIEC did not

[45] *Id.*
[46] Direct Testimony of Bradley G. Mullins at 16, 25 (WIEC Exhibit No. 202).
[47] Supplemental Direct Testimony of Ramon J. Mitchell at 6 (Correction 4 and Correction 5) (RMP Exhibit 10.4).
[48] *Id.*, at 7-8 (Update 1 and Update 3).

object to either of these actual modeling changes, which decreased the 2024 NPC forecast by a total of $219 million total-Company,[49] or $30.8 million Wyoming-allocated when combining the isolated NPC impacts of both those new modeling techniques.[50] If WIEC is proposing to disallow new modeling techniques included in the NPC Update, then NPC will significantly increase. Therefore, the Company does not agree with WIEC's recommendation to exclude modeling changes made in the NPC update.

Q. WIEC claims that the correction to "Contingency Reserves for Non-Owned Generation" was unsupported.[51] How do you respond?

A. The correction was fully supported in the Aurora project. Furthermore, the Company provided written detail in response to WIEC Data Request ("DR") 18.3[52] explaining precisely where, in the Company's workpapers, to find the original values and the corrected values. Between the Company's workpapers inclusive of the Aurora project and DR 18.3, the "Contingency Reserves for Non-Owned Generation" correction was fully supported. Even more noteworthy is that WIEC provided no evidence to support any claim that the correction was inaccurate or otherwise not exactly as the Company represented it. The correction to the "Day-Ahead/Real-Time Volume Component" is explained in exhaustive detail below in Section IX(C).

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[49] *Id.* at 7-8 (Update 1 and Update 3).
[50] The cumulative NPC impact would be less than the sum of the two isolated NPC impacts.
[51] Direct Testimony of Bradley G. Mullins at 28 (WIEC Exhibit No. 202).
[52] The Company's response to WIEC DR 18.3 was served on August 8, 2023.

Q. WIEC also questions the Company's System Balancing Adjustment included in the NPC update because, according to WIEC, the concept of "[s]ystem balancing impact of adjustments" was not described in your testimony.[53] How do you respond?

A. The system balancing impact of adjustments is when the cumulative effect of two or more corrections or updates cancel portions of each other out. A simplified example illustrates this phenomenon. The increased flexibility in the OTR (which is a new modeling method in the NPC Update) increases the generation of gas plants in the state of Utah. Lowered gas prices also increase the generation of gas plants in the state of Utah. On an isolated basis, if the NPC impact of the increased flexibility in the OTR is calculated, then there will be a certain increase to gas generation in the state of Utah when this calculation is done in isolation, without consideration of lowered gas prices. The NPC impacts presented in the NPC Update[54] are exactly this type of isolated impact without consideration of other changes on the Company's system.

On the other hand, if the NPC impact of lowered gas prices is calculated, there will also be a certain increase to gas generation in the state of Utah when this calculation is done in isolation, without consideration of the increased flexibility in the OTR. However, if both adjustments are analyzed together (analyzed as one cumulative adjustment) then it is possible that after the increased flexibility in the OTR increases Utah gas generation, the Utah gas generation is high enough such that there may be no more capacity left for the lowered gas prices to bring about additional increases in Utah gas generation.

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[53] Direct Testimony of Bradley G. Mullins at 18 (WIEC Exhibit No. 202).
[54] Supplemental Direct Testimony of Ramon J. Mitchell at 1 (RMP Exhibit 10.6).

In this cumulative analysis, the combined effect of the increased flexibility in the OTR and the lowered gas prices may show limited impact to NPC from the lowered gas prices (or vice versa), but on an isolated basis there may be some substantive NPC impact shown for both the increased flexibility in the OTR and simultaneously for the lowered gas prices. The difference between this cumulative analysis and these two isolated analyses is a "system balancing impact of adjustments" and demonstrates a dampened NPC impact in the cumulative analysis as compared to the sum of the isolated analyses.

Q. Has Mr. Mullins previously explained exactly what a system balancing adjustment is designed to do?

A. Yes. In testimony filed in May 2023 in Oregon, Mr. Mullins explained his own "balancing adjustment" used to account for the totality of his NPC recommendations:

> Each of the NPC impacts in this testimony were calculated as one-off adjustments, without considering the impacts of any other adjustments. This was done to isolate the impacts of individual modeling changes, without having the impacts skewed by the order in which the adjustment calculations were performed. There are, however, counterbalancing impacts between different adjustments. . . To account for these counterbalancing impacts, as a last step in my modeling, a [NPC] model run was prepared that consolidates all of the adjustments described in testimony.[55]

Q. Was the Company's calculation of a system balancing adjustment here the same approach used in prior rate cases?

A. Yes. The Company's NPC Update in this GRC replicated the prior NPC update conducted in the 2015 GRC. This concept of "system balancing impact of

[55] OPUC Docket No. UE 416, Opening Testimony of Bradley G. Mullins at 36 (AWEC/100).

adjustments"[56] is identical to the concept of "Impact of combining adjustments"[57] presented by the Company in that 2015 GRC NPC Update.

Q. Does WIEC have any specific objection to the System Balancing Adjustment in this case?

A. Yes. WIEC claims that "to force its request in this case to match its final modeling run, [the Company] applied a $164,182,948 upward adjustment at the end of its comparison to account for the unexplained variance that it called a System Balancing Adjustment."[58]

Q. How do you respond?

A. Consistent with the discussion above, and Mr. Mullins' own prior testimony, each row (isolated modeling scenario) in the NPC Update's list of corrections and updates[59] is an isolated modeling scenario, which is a one-off sensitivity. Each isolated modeling scenario does not contemplate any of the other isolated modeling scenarios. The Company's NPC proposal is **none** of these isolated modeling scenarios. Rather, the Company's NPC proposal is a cumulative modeling scenario which contemplates all scenarios in one modeling run. As I have explained above, the difference between this **cumulative** modeling scenario (NPC proposal) and the many **isolated** modeling scenarios is a "system balancing impact of adjustments" and demonstrates a dampened NPC impact in the cumulative scenario as compared to the sum of the isolated scenarios. WIEC's characterization that the NPC proposal can be calculated by simply

[56] Supplemental Direct Testimony of Ramon J. Mitchell at 1 (RMP Exhibit 10.6).
[57] *In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of $32.4 Million per Year or 4.5 Percent*, Docket No. 20000-469-ER-15, (Record No. 14076) Exhibit Accompanying Rebuttal Testimony of Brian S. Dickman, Corrections and Updates at 1 (Exhibit RMP___(BSD-2R)).
[58] Direct Testimony of Bradley G. Mullins at 19 (WIEC Exhibit No. 202).
[59] Net Power Cost List of Corrections and Updates at 2 (RMP Exhibit 10.6).

adding the impacts of the many isolated scenarios is erroneous, demonstrated as erroneous in Figure AURORA-2 above in Section III, contrary to Mr. Mullins' own prior testimony, and therefore lacks credibility.

VI. COAL SUPPLY

A. Background

Q. In your supplemental direct testimony you referenced "coal supply limitations" as offsetting the decrease in NPC resulting from the use of the updated, and lower, OFPC.[60] What coal supply limitations are you referring to?

A. Generally, the amount of coal available to burn in 2024 is limited by the amount of coal the Company can realistically expect to receive in 2024, as explained in the rebuttal testimony of Company witness Mr. Owen. This means that it is physical supply constraints, rather than economics, that are limiting coal generation. To exemplify this fact, the Company conducted a counterfactual analysis wherein the Aurora model was provided the opportunity to burn twice the amount of coal[61] at both Hunter and Huntington and the Aurora model burned more coal at both those plants and NPC was driven lower. This result is intuitive because on a dollar per megawatt-hour ("$/MWh") basis, coal is on average substantially cheaper than market purchases.

[60] Supplemental Direct Testimony of Ramon J. Mitchell at 4 (RMP Exhibit 10.4).
[61] This coal is fictional, and this modeling is solely to provide an example and not representative of any real coal supply assumptions.

B. Reply to WOCA

Q. WOCA claims to have found "several irregularities" because the forecasted 2024 generation at the Hunter, Huntington, and Naughton plants is lower than actual generation from 2020 through 2022.[62] How do you respond?

A. The changes observed by WOCA are not irregularities. Rather, as discussed by Company witness Mr. Owen, coal supply limitations at the Hunter and Huntington plants are decreasing generation relative to the historical levels, because there is no more coal to burn.

As relevant to my testimony, when WOCA's Confidential Table 2 is updated, it shows no irregularities. In particular, in Confidential Table COAL-1, I have: (1) updated WOCA's Confidential Table 2 with 2023 data through ratio extrapolation of the first seven months of 2023 historical data; (2) updated WOCA's Confidential Table 2 with the NPC forecast after removal of the OTR;[63] and (3) separated out the coal units of the Naughton plant. Below is the updated table as Confidential Table COAL-1 and one figure for each line item, as Confidential Figures COAL-1 – COAL-4.

[62] Direct Testimony of Colin T. Fitzhenry at 8 (WOCA Exhibit No. 603).
[63] As explained below in Section VII, the OTR is proposed to be removed from the NPC forecast.

Confidential Table COAL-1

[redacted]

Confidential Figure COAL-1

[redacted]

Confidential Figure COAL-2

[redacted]

Confidential Figure COAL-3

[redacted]

Confidential Figure COAL-4

[redacted]

With this updated information, the coal units at Hunter, Huntington and Naughton are all within reason in the context of 2023 and the historical trend.

Q. WOCA also noted an "irregularity" at the Gadsby combustion turbines ("Gadsby CT") because that plant significantly increased generation relative to historical levels.[64] How do you respond?

A. Restricting the generation at Gadsby CT will increase NPC, all other things equal. So while its generation has increased in response to the market conditions and operational / policy changes described throughout my testimony, that increased generation has decreased NPC.

[64] Direct Testimony of Colin T. Fitzhenry at 9 (WOCA Exhibit No. 603).

C. Reply to WIEC

Q. WIEC asserts that the system balancing impact of adjustments (discussed above) is too large and claims it is the result of "undocumented changes to coal costs included in the final, July Update forecast."[65] How do you respond?

A. WIEC claims that the Company "materially misrepresented the impact of the coal supply update and the associated changes to coal costs that were included in the July Update" and that WIEC's "model runs showed that, relative to the initial filing, the coal cost update increased [Rocky Mountain Power's] NPC forecast by $115,225,600 on a total-company basis—not $6,540,170 as presented in the Company's Update filing."[66]

I have examined WIEC's workpapers and their analysis is in error. In calculating this purported increase of "$115,225,600," WIEC conducted an analysis that erroneously assumed that the costs associated with take-or-pay (minimum coal volume) provisions in the Company's coal supply agreements do **not** increase with the volume of coal received under those take-or-pay provisions. In doing so, WIEC's analysis erroneously took the high take-or-pay coal volumes from the Company's **initial filing** and priced them at the low take-or-pay coal costs from the Company's **NPC Update**. After correcting for this error WIEC's analysis shows that the Company's coal supply update would result in a **decrease** to NPC of $46 million total-Company, or $6.4 million Wyoming-allocated.

Q. Is this the extent of WIEC's calculation errors regarding the coal supply update?

A. No. Additionally and erroneously, WIEC *first* eliminated 22,600,000 metric million British thermal units ("MMBtu") of incremental coal volume flexibility at the

[65] Direct Testimony of Bradley G. Mullins at 20 (WIEC Exhibit No. 202).
[66] *Id.,* at 20-21.

Huntington coal plant, *second,* eliminated 4,800,000 MMBtu of incremental coal volume flexibility at the Naughton coal plant, *third,* eliminated 2,352,000 MMBtu of incremental coal flexibility at the Hayden coal plant and then, *fourth,* priced the incremental coal volume flexibility at the Craig plant at the lower price from the NPC Update. These errors were all accomplished as Mr. Mullins attempted to revert the model back to the initial filing's coal assumptions for purposes of his comparison. When these WIEC errors are corrected, the NPC decrease of $46 million mentioned above reverts back to a NPC increase of $6.5 million as indicated in the NPC Update.[67] Together, these straightforward corrections to WIEC's modeling invalidate its claim that the Company misrepresented the impact of coal costs in the NPC Update and further demonstrate fundamental misunderstanding and errors in WIEC's modeling.

WIEC's errors here, however, are not entirely surprising. In his Oregon testimony filed two days after WIEC's Wyoming testimony, Mr. Mullins similarly claimed that the Company's NPC update in Oregon misrepresented the impact of updated coal costs.[68] In the Oregon case, Mr. Mullins' mistake was made in Aurora because he failed to import the correct coal prices from the initial filing when making his comparison.[69] While Mr. Mullins' specific errors here are different from the specific errors made in his Oregon testimony, they reflect the same basic misunderstandings that flow throughout his testimony.

[67] Net Power Cost List of Corrections and Updates at 2 (RMP Exhibit 10.6).
[68] OPUC Docket No. UE 420, Rebuttal Testimony of Bradley G. Mullins at 11-12 (AWEC/200).
[69] *See,* OPUC Docket No. UE 420, Surrebuttal Testimony of Ramon Mitchell at 65-72 (PAC/800).

Q. Are there any corrections that need to be made to WIEC's testimony related to the coal cost update?

A. Yes. WIEC claims that Rocky Mountain Power "actually used the AURORA project submitted in the Oregon TAM[70] as the starting point for the July Update, rather than the AURORA model submitted in [the Company's] initial filing in this case."[71] This is incorrect.

Q. What is the basis for WIEC's claim that the Company was comparing its updated coal costs in this case to the coal costs in the Oregon filing?

A. In Figure BGM-4, WIEC highlighted a file titled "Aurora_TAM_2024_Update_InputDB.xdb."[72] WIEC appears to believe that because the file references the "TAM_2024" in the name, the Company "actually used the AURORA project submitted in the Oregon TAM" as the comparator for the coal cost update. However, WIEC does not appear to recognize that this type of "xdb" file used by Aurora is a database file (as suggested by the "DB" in the filename), and more specifically (as suggested by the "InputDB" in the filename), this type of "xdb" file is an input database file that contains the base input level data representing the Company's holistic six-state service territory. These inputs include things such as hydro forecasts, resource characteristics, transmission capacity, etc.

WIEC acknowledges the Company "filed Rebuttal Testimony in [Oregon] on July 24, 2023, the same day as the [Wyoming] Update."[73] Therefore, it is expected that

[70] For reference, the "Oregon TAM" is the Oregon transition adjustment mechanism docket in which Mr. Mullins submitted the testimony I have discussed above.
[71] Direct Testimony of Bradley G. Mullins at 21-22 (WIEC Exhibit No. 202).
[72] *Id.*, at 22. WIEC conveniently ignores the second file in the screenshot titled "Aurora_WY_GRC_2024_Update.apz."
[73] *Id.*

these base inputs for the six-state service territory would be the same,[74] given that the Company is modeling the same system. In other words, WIEC observed that the Company used the same base inputs for the Oregon and Wyoming NPC updates—which were performed at the same time—and then concluded that the Company's Wyoming update was being erroneously compared to the Oregon update, rather than the Wyoming initial filing. That conclusion is not only factually incorrect, it is illogical based on the Aurora files WIEC referenced in its testimony.

Q. WIEC claims that "neither WIEC nor the Commission has a basis to evaluate or consider the reasonableness of the coal costs included in AURORA in the July Update."[75] How do you respond?

A. Please refer to the rebuttal testimony of Company witness Mr. Owen for detail on the Company's current coal supply limitations, coal costs, and the state of regional coal industries, which contribute to a decline in coal supply and increase in coal prices for a number of Company coal plants.

Furthermore, the supposed inconsistencies identified by WIEC result entirely from WIEC's own errors and misunderstanding of Aurora modeling, as discussed above. In fact, the Company correctly modeled the updated coal costs, correctly compared the NPC impact of updated coal costs to the initial filing, and correctly calculated a system balancing adjustment to incorporate the cumulative impact of each change reflected in the NPC update.

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[74] Prior to state-specific modifications which are performed in the "Aurora_WY_GRC_2024_Update.apz" file.
[75] Direct Testimony of Bradley G. Mullins at 25 (WIEC Exhibit No. 202).

VII. OZONE TRANSPORT RULE

A. Background

Q. Has the Company's recommendation for the OTR changed as a result of a recent court order?

A. Yes. It is my understanding that on July 27, 2023, the Tenth Circuit Court of Appeals issued an order that stays the enforcement of the OTR in Utah pending the outcome of the ongoing litigation.[76] Based on that order and the continuing uncertainty around Wyoming, the Company proposes to remove the OTR from the NPC forecast for both Utah and Wyoming. The NPC impact of removing the OTR is a reduction of $22 million total-Company, $3.2 million, Wyoming-allocated.

B. Reply to WOCA

Q. Notwithstanding the Company's proposal to not include the OTR in the NPC forecast, do you have any response to WOCA's OTR testimony?

A. Yes. WOCA states that the stay referenced above was granted on June 27, 2023.[77] This would imply that the Company knew about the stay before the filing of the supplemental direct testimony, but this is not the case. WOCA appears to have made a typographical error; the stay was granted on July 27, 2023,[78] which was after the filing of the supplemental direct testimony.

Furthermore, WOCA states that the impact of the OTR adjustment is $135 million.[79] However, as I outlined in my supplemental direct testimony, the OTR

[76] *State of Utah v. U.S. Env't Prot. Agency*, Case No. 23-9509, Order (10th Cir. July 27, 2023) (available at https://www.oag.ok.gov/sites/g/files/gmc766/f/documents/2023/stay_order.pdf) (last visited Sept. 18, 2023) [hereinafter "*Utah v. EPA* Stay Order"].
[77] Direct Testimony of Colin T. Fitzhenry at 12 (WOCA Exhibit No. 603).
[78] *Utah v. EPA* Stay Order.
[79] Direct Testimony of Colin T. Fitzhenry at 13 (WOCA Exhibit No. 603).

modeling method was updated, and the NPC impact was reduced.[80] The impact of removing the OTR is as I have stated above, a reduction of $22 million total-Company, $3.2 million, Wyoming-allocated.

C. Reply to WIEC

Q. Notwithstanding the Company's proposal to not include the OTR in the NPC forecast, do you have any response to WIEC's OTR testimony?

A. WIEC claims that for the OTR, the Company "modeled . . . restrictions in **every** month of the year" even though the OTR only applies during the OTR season from May to September.[81] This is another example of the rather serious issues surrounding WIEC's usage and understanding of both NPC modeling in general and Aurora specifically that I reference in Section III above.

Q. Please elaborate.

A. The below Figure OTR-1 is taken from the Company's Aurora project.

Figure OTR-1

Set ID	Constraint Type	Item ID	Limit	Limit Units	Emission Pricing	Limit Type	Limit Definition
PacifiCorp _Emit_100	Emission	NOX	yr_PacifiCorp _Limit_100	Ton	sc_PacifiCorp _Emit_	Year	mn_OTR
Utah _Emit_100	Emission	NOX	yr_Utah _Limit_100	Ton	sc_Utah _Emit_100_	Year	mn_OTR
Utah _Emit_121	Emission	NOX	yr_Utah _Limit_121	Ton	sc_Utah _Emit_121_	Year	mn_OTR
Wyoming _Emit_121	Emission	NOX	yr_Wyoming _Limit_121	Ton	sc_Wyoming _Emit_	Year	mn_OTR

This section of the project is the part that governs the imposition of the OTR on the NPC forecast. WIEC is perhaps confused on the entry in the column titled "Limit Type" which reads "Year" and perhaps confused on the entry in the column titled "Limit" which contains entries that begin with "yr." However, refer to the highlighted column

[80] Supplemental Direct Testimony of Ramon J. Mitchell at 7 (Update 1) (RMP Exhibit 10.4).
[81] Direct Testimony of Bradley G. Mullins at 57 (WIEC Exhibit No. 202) (emphasis added).

titled "Limit Definition." It specifies a set of time intervals smaller than the period declared in the "Limit Type" column. For example, this column can constrain resource dispatch for only a subset of the months of each year when the "Limit Type"=Year. This restriction is controlled by entering a reference to a monthly time series ("mn_") with values of 1 for the effective months and 0 (zero) for other months. Accordingly, the entry in the "Limit Definition" table instructs Aurora as to which months of the year the OTR should be applied to. The below Figure OTR-2 is the definition provided to Aurora for that "mn_OTR" entry in the "Limit Definition" table.

Figure OTR-2

OTR

	ID	Use	1	2	3	4	5	6	7	8	9	10	11	12
1	OTR	OTR Seasons	0	0	0	0	1	1	1	1	1	0	0	0

In the column header of the above figure, the numbers 1 through 12 correspond to the 12 months in a year. It is evident that the OTR season is activated by an entry of "1" during the months of May to September and deactivated with an entry of "0" during the other months of the year. Furthermore, the Aurora software contains a "Help" file, and this information is available to WIEC and any other user of Aurora. The help file clearly identifies how the columns function and the Company's usage of Aurora's features to restrict the Ozone Season to May through September is clearly explained. I provide the appropriate extract from the help file below in Figure OTR-3.

Figure OTR-3

Limit Definition Column
Column Type = Text

The Limit Definition column specifies a set of time intervals smaller than the period declared in the Limit Type column. For example, use this column to constrain resource dispatch for only a subset of the months of each year when the Limit Type = Year. This restriction is controlled by entering a reference to a monthly time series (mn_) with values of **1** for the effective months and **0** (zero) for other months. An annual times series (yr_) may also be used in this column as long monthly time series are nested inside it.

NOTE: Inputs can only be specified by a monthly or annual time series. For information on how to specify a time series for a variable, see Entering a Time Series.

- Input Tables
  - Constraint Table
    - Limit Definition Column

VIII. WASHINGTON CAP AND INVEST PROGRAM

A. Reply to WOCA

Q. Please describe the Washington Cap and Invest Program.

A. Generally, the Company is required to purchase GHG allowances for emissions from plants located in Washington. For the Company, this impacts the generation from the Chehalis plant. As explained in the Company's initial filing, the Washington Cap and Invest Program is functionally the same as the Wyoming wind tax.[82]

Q. WOCA recommends removal of the costs imposed by the Washington Cap and Invest Program and the associated impact from the NPC forecast.[83] How do you respond?

A. As discussed by Company witness Ms. Joelle R. Steward, it is reasonable for Wyoming customers to pay the generally applicable compliance costs for generation at Chehalis if Wyoming customers receive the benefits of Chehalis.

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[82] Direct Testimony of Ramon J. Mitchell at 17-18 (RMP Exhibit 10.0).
[83] Direct Testimony of Colin T. Fitzhenry at 13-14 (WOCA Exhibit No. 603).

Q. Do Wyoming customers benefit from Chehalis, even accounting for the costs of the Washington Cap and Invest Program?

A. Yes. The Company performed an Aurora run without Chehalis and NPC increased $133 million total-Company, $19 million Wyoming-allocated, relative to the NPC Update. This result is not surprising because any time that Chehalis dispatched in Aurora, it did so with the added GHG compliance costs. If Chehalis did not dispatch in those hours, the Company would have to rely on other generation, which—by definition—will be higher cost, otherwise Chehalis would not have dispatched in the first place. Therefore, Wyoming customers are receiving benefits from Chehalis even with the GHG compliance costs.

B. Reply to WIEC

Q. WIEC claims that the Company is including the costs of the Washington Cap and Invest Program emissions allowances in the wrong Federal Energy Regulatory Commission ("FERC") account.[84] Is that true?

A. No. Company witness Mr. Nicholas L. Highsmith provides detail on the inaccuracy of WIEC's claim.

Q. Setting aside WIEC's mistaken understanding of FERC accounting, WIEC discusses at length the allocation of the costs associated with the increased dispatch cost at the Chehalis plant resulting from the Washington Cap and Invest Program.[85] How do you respond?

A. Company witness Ms. Steward addresses WIEC's larger arguments around appropriate allocation of costs resulting from the Cap and Invest Program.

[84] Direct Testimony of Bradley G. Mullins at 34 (WIEC Exhibit No. 202).
[85] Direct Testimony of Bradley G. Mullins at 35-39 (WIEC Exhibit No. 202).

Q. WIEC argues that modeling the impact of GHG allowances produces uneconomic dispatch at Chehalis.[86] How do you respond?

A. WIEC's claim of uneconomic dispatch does not hold up under scrutiny. WIEC claims the "cost of uneconomic dispatch" to be: (1) the increase in total-Company NPC resulting from applying a GHG allowance price to Chehalis; less (2) the cost of the GHG allowances themselves. In a hypothetical scenario where the GHG allowance price were $1,000/MWh and the Chehalis plant never generated at all (0 MWh) because of this high cost, then the cost of the GHG allowances would be $0; (0 MWh * $1,000/MWh). Per WIEC's logic then, the "cost of uneconomic dispatch" in this scenario would be: (1) the increase in NPC resulting from applying a GHG allowance price to Chehalis (which would be entirely the cost of replacement energy); less (2) the cost of the GHG allowances themselves (which would be $0 since Chehalis never generated). In this scenario, this "cost of uneconomic dispatch" would then be entirely the cost of replacement energy, per WIEC's logic. Defining replacement energy as uneconomic dispatch is inaccurate and WIEC's statement that the "cost of uneconomic dispatch" contributed to $9,804,235 (a total-Company number) is therefore an inaccurate statement.

IX. DAY-AHEAD / REAL-TIME ADJUSTMENT

A. Background

Q. Please describe the DA/RT adjustment.

A. The Company incurs system balancing costs that are not reflected in the Company's OFPC nor modeled in the Company's NPC production cost model. To address this

[86] Direct Testimony of Bradley G. Mullins at 33 (WIEC Exhibit No. 202).

deficiency, the Company uses the DA/RT adjustment to more accurately model system balancing transaction prices and volumes. The DA/RT adjustment consists of two components, a price component and a volume component.

Q. Please describe the price component of the DA/RT adjustment.

A. The price component of the DA/RT adjustment addresses the costs incurred by the Company as a result of multiple variables within a dynamic system in which the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods.

To better reflect the market prices available to the Company when it transacts in the real-time market, the Company includes separate prices for in-model sales and separate prices for in-model purchases in Aurora. Aurora is the Company's current production cost model. These prices account for the historical price differences between the Company's purchases and sales compared to the monthly average market-indexed prices (the OFPC).

Q. Please describe the volume component of the DA/RT adjustment.

A. The Company reflects additional volumes to account for the use of monthly, daily, and hourly products. In actual operations, the Company continually balances its market position—first with monthly products, then with daily products, and finally with hourly products. The products used to balance the Company's forward position in the wholesale market are available in flat 25 MW blocks. The Company's load and resource balance, however, varies continuously each hour in quantities that may vary widely from a flat 25 MW block. Thus, in real world operations, the Company must continuously purchase or sell additional volumes to keep the system in balance.

In contrast, Aurora has perfect foresight and can model wholesale market transactions at whatever volume is necessary (within fractions of a MW) to balance the system. Because of Aurora's perfect foresight, it balances the system with far fewer transactions than would be the case in actual operations. The DA/RT volume component adds additional volumes and associated cost to the NPC forecast to more accurately model those transactions in actual operations that are necessary to balance the Company's system.

B. Reply to WOCA

Q. WOCA states that the "conditions described for the DA/RT adjustment could be eliminated by joining [the] EDAM" and recommends a reduction in NPC of $66 million, total-Company, because of this.[87] How do you respond?

A. WOCA's assertions *could* have relevance if the Company were joining the EDAM at the beginning of 2024. However, as of August 2023, the Company and the California Independent System Operator ("CAISO") have jointly revised the start date of the EDAM to 2026.[88] Currently, the entirety of 2024, the entirety of 2025 and a portion of 2026 will not reflect any EDAM operations and therefore: (1) the DA/RT adjustment is still necessary; and (2) WOCA's NPC reduction recommendation is premature.

[87] Direct Testimony of Colin T. Fitzhenry at 15 (WOCA Exhibit No. 603).

[88] CAISO, *EDAM Fact Sheet* at 2 (2023) (available at http://www.caiso.com/Documents/extended-day-ahead-market-edam-fact-sheet.pdf) (last visited Sept. 18, 2023) (anticipating onboarding EDAM participants in 2026).

C. Reply to WIEC

Q. WIEC recommends removing the DA/RT price component because according to WIEC the volume component of the DA/RT adjustment renders the price component "perfunctory, except to the extent that [the price component] modified the way thermal plants were dispatched."[89] Is this testimony consistent with Mr. Mullins' prior testimony related to the DA/RT adjustment?

A. No. Mr. Mullins has made the opposite point and argued that the volume component was "perfunctory." For example, in a 2017 Oregon hearing, Mr. Mullins testified that as he had "sort of come to further understand the Company's adjustment, the volume piece is really superfluous. It's kind of a cosmetic part of the adjustment. It really doesn't matter."[90]

Q. WIEC claims that the DA/RT adjustment is no longer necessary in Aurora because Aurora does not contain the same level of transaction optimization as GRID and that Aurora is producing less optimal dispatch than GRID.[91] How do you respond?

A. As discussed in Section III above, WIEC's testimony regarding Aurora's optimization is without merit and contrary to Mr. Mullins' own prior testimony describing how Aurora is more sophisticated than GRID.

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[89] Direct Testimony of Bradley G. Mullins at 41 (WIEC Exhibit No. 202).
[90] *In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, OPUC Docket No. UE 323, Hearing Transcript at 191:9-13 (Aug. 31, 2017).
[91] Direct Testimony of Bradley G. Mullins at 43-44 (WIEC Exhibit No. 202).

Q. WIEC recommends an adjustment that entirely removes the DA/RT price component[92] and removes a portion of the DA/RT volumes.[93] How do you respond?

A. As an initial matter, by eliminating the price component, WIEC's recommendation fails to capture the true cost of balancing the Company's system in the short-term markets which is accomplished in the NPC forecast by adjusting forward market prices (the OFPC) to reflect variations between the average market-indexed prices over each month and actual realized prices for the Company's day-ahead and real-time transactions in that month.

By also eliminating the DA/RT volumes from the volume component, WIEC's recommendation additionally fails to capture the volumetric inefficiencies of the operational practice of transacting on a monthly basis using, as an example, standard 25 MW increment, 16-hour block products, rebalancing on a daily basis using standard 25 MW increment eight-hour block products, and finally closing the remaining position on an hourly basis in real-time markets, as compared to Aurora's perfect hourly trade execution, within fractions of a megawatt.

WIEC would eliminate entirely the component of the DA/RT adjustment designed to address market price inefficiency and also entirely eliminate that portion of the component of the DA/RT adjustment designed to address volumetric inefficiencies in trading. However, the DA/RT adjustment has always contained two critical components and both are separately and completely necessary to capture market price inefficiency (price component) and trading volume inefficiency (volume

[92] Direct Testimony of Bradley G. Mullins at 41 (WIEC Exhibit No. 202).
[93] *Id*., at 46-47.

component). I explain in detail below how WIEC has presented no persuasive evidence in this case that eliminating any of these components in entirety or in portion will produce a more accurate forecast.

Q. In its Confidential Figure BGM-5, WIEC purports to show a comparison of the Aurora model's 2024 forecast levels of net short-term purchases to the historical net short-term purchases and a 2020 rate case forecast of 2021 to show an apparently dramatic increase in net short-term purchases in 2024.[94] Do you agree with how WIEC presented its data?

A. No. By "netting" the purchases against the sales, the underlying patterns in short-term purchases separate from the underlying patterns in short-term sales is not visible to the reader.

Additionally, the historical data includes energy imbalance market ("EIM") purchase and sales volumes even though Aurora's (and GRID's) forecasts do not include that data. This means that WIEC compared the NPC *forecast* volumes—with no EIM volumes—to historical NPC *actual* volumes—with EIM volumes.

The following Confidential Figures DART-1 and DART-2 below: (1) separate purchases from sales to show patterns otherwise lost by offsetting (netting) the data before presenting it; (2) remove the EIM volumes from the historical data to allow for an accurate and appropriate comparison to the NPC forecast (which has no EIM volumes); (3) take the first seven months of 2023 actual data and ratio it out to proxy for 2023; and (4) move the "GRID 2020 GRC" column to its more appropriate place in between "2020" and "2021," which is the more appropriate vintage.

[94] *Id*., at 44.

Confidential Figure DART-1

[redacted]

Confidential Figure DART-2

[redacted]

In 2024, the NPC forecast in the NPC Update includes the impact of the OTR, the Jim Bridger gas conversion and associated outage, and the removal of the Klamath dams—all of which will increase the short-term purchases relative to the historical data, inclusive of 2023, as shown in Confidential Figure DART-1.

Q. WIEC claims that the excessive levels of short-term purchases show that Aurora is "not optimizing short-term sales and purchase transactions at the same level as GRID and in a manner that is less efficient than experienced historically."[95] WIEC continues that this "is an indication that the DA/RT method, as [Rocky Mountain Power] has implemented it, is not necessary for the AURORA model."[96] How do you respond?

A. Based on: (1) the breakdown and re-compilation of WIEC's incomplete analysis and the demonstration above of an accurate portrayal of realistic levels of short-term firm purchases in the NPC forecast; and (2) the fact that WIEC's testimony regarding Aurora's optimization is without merit and contrary to Mr. Mullins' own prior testimony describing how Aurora is more sophisticated than GRID; I do not find WIEC's argument on the reasonability of removing the DA/RT price component or DA/RT volumes complete or valid.

Q. If the DA/RT adjustment is not the cause of the increase in short-term firm purchases, what is?

A. The increase in short-term purchases relative to historical levels reflects market conditions and operational / policy changes limiting generation in the 2024 forecast, as discussed in my initial filing and reiterated above.[97] It is not surprising that limitations on generation from the Company's resources would require increased reliance on market purchases. The level of short-term purchases WIEC identifies therefore is not

[95] *Id*., at 44-45.
[96] *Id.,* at 45
[97] Direct Testimony of Ramon J. Mitchell at 10 (RMP Exhibit 10.0).

surprising and does not indicate anything meaningful about Aurora, GRID, or the DA/RT adjustment.

Q. WIEC compares historical market transaction dollars to the Aurora modeled market transaction dollars in this year's GRC (combined with the NPC impact of the DA/RT volume component correction) and concludes that the impact is significantly higher with Aurora.[98] Do you agree?

A. No. As an initial matter, WIEC is not comparing comparable data. I elaborate on this further below. However, in order to respond to WIEC's analysis, it is important to establish some simplified terminology for three different categories of costs related to the DA/RT volume component:

- *"Real World Transaction Loss"* refers to the total amount of **actual** historical net cost incurred when day-ahead or real-time market transactions are executed at prices unfavorable to the OFPC,[99] or the total amount of that net cost expected to be **actually** incurred in the test period. These costs include real-world inefficiencies associated with multi-hour block products, trading in 25 MW increments, and a lack of certainty regarding the future.
- *"Perfect Foresight Transaction Loss"* refers to the total amount of net cost incurred from **forecast** hourly **in-model** (Aurora or GRID) transactions that are executed at prices unfavorable to the OFPC.[100] These costs reflect no further price or volume inefficiencies, result from transactions executed to within a fraction of a MW, and result from Aurora's ability to know the future with

[98] Direct Testimony of Bradley G. Mullins at 45-46 (WIEC Exhibit No. 202).
[99] Transactions that are favorable to the OFPC are present as well but, the net is unfavorable.
[100] This is the use of the DA/RT price component which is only ever applied to the perfect in-model transactions.

certainty.

- *"Adjustment to Get to Real-World Transaction Loss"* refers to the test period dollars that the DA/RT volume component adds to the *"Perfect Foresight Transaction Loss"*[101] to get to the expected *"Real-World Transaction Loss"* in order to account for costs associated with real-world trading *inefficiencies* and real-world *lack* of perfect foresight[102] (for example, trading in 25 MW increments, or trading in 16-hour block products and rebalancing in real-time, or not knowing the future).

Confidential Figure DART-3 below illustrates what the "*Adjustment to Get to Real-World Transaction Loss*" would have been if the *"Real World Transaction Loss"* were known with certainty during the preparation of the NPC forecast. Please note that for calendar years 2023 and 2024 I have proxied for the *"Real World Transaction Loss"* based on extrapolation of historical transactions and for years other than Wyoming GRC test periods, I have proxied with total-Company test period data from annual NPC filings in Oregon. Confidential Figure DART-3 below has two columns stacked on top of each other, *"Perfect Foresight Transaction Loss"* and *"Adjustment to Get to Real-World Transaction Loss."* The sum of these two stacked columns is the *"Real World Transaction Loss."*

That is to say, Confidential Figure DART-3 shows: (1) what the costs of real-world trading inefficiencies (DA/RT volume component) **actually were** for 2016 to

[101] The *"Adjustment to Get to Real-World Transaction Loss"* are expected and designed to be costs because they reflect the inefficiencies associated with actual operations, and the only component of revenue embedded into them are arbitrage revenues, which were $9.3 million in 2022.
[102] These dollars are not captured by the DA/RT price component which only impacts the perfect foresight / perfectly efficient hourly transactions that come out of Aurora's modeling.

2022; and (2) what the costs might be for 2023 and 2024, based on extrapolation. These costs—as mentioned above—are labeled *"Adjustment to Get to Real-World Transaction Loss."*

Confidential Figure DART-3

[redacted]

However, because the to-be-incurred *"Real World Transaction Loss"* is not known beforehand (*e.g.*, not known for 2024 during the filing of this GRC) Confidential Figure DART-4 below illustrates what the *"Adjustment to Get to Real-World Transaction Loss"* was forecast to be for each year since 2016, inclusive of this GRC which corrected an error. Note that for 2023 and 2024 I have defined *"Adjustment to Get to Real-World Transaction Loss"* as *"Artificial Arbitrage Revenue"* so as to draw attention to them in a different color and to define the term for later use, and, for years other than Wyoming GRC test periods, I have proxied with total-Company test period data from annual NPC filings in Oregon.

That is to say, Confidential Figure DART-4 shows what the costs of the real-world trading inefficiencies (DA/RT volume component) were **forecast to be** for

2016 to 2024. These costs—as mentioned above—are labeled either *“Adjustment to Get to Real-World Transaction Loss”* or *“Artificial Arbitrage Revenue”*.

Please note that the *“Adjustment to Get to Real-World Transaction Loss”* value in the “Corrected 2024” column in Confidential Figure DART-4 is enlarged so that it is visible to the reader. The actual value is -$791,170 (note the negative sign).

Confidential Figure DART-4

[redacted]

As explained above, the DA/RT volume component dollars (*“Adjustment to Get to Real-World Transaction Loss”*) are designed to capture *inefficiencies* and attendant *costs* in actual operations that are not captured in Aurora. Real-world *inefficiencies* in trading cannot produce such substantial *revenue* (*“Artificial Arbitrage Revenue”)* when compared to Aurora’s perfect foresight / perfectly efficient optimized system dispatch. The illustrations above demonstrate: (1) what the DA/RT volume component is designed to do; (2) what the DA/RT volume component actually did; and (3) the clearly erroneous result (*"Artificial Arbitrage Revenue"*) in the direct testimony of this GRC, which was corrected as the "Day-Ahead/Real-Time Volume Component" entry in the NPC update.[103]

Q. Please clarify the distinction between "*Artificial* Arbitrage Revenue" and "*Real* Arbitrage Revenue."

A. Artificial arbitrage revenue is revenue from the DA/RT volume component that is in excess of any reasonable metric of real arbitrage revenue and not achievable in the test period. Real arbitrage revenue is synonymous with the historical gain present in the four-year historical market transaction data that is a part of the volume component of the DA/RT adjustment. This historical gain is the combination of actual arbitrage transactions that create revenue and the historical revenue calculated when the Company buys below the OFPC and sells above the OFPC. In the past four years, this real arbitrage revenue has been between $6.2 million per year and $9.3 million per year. In the context of my definitions above, consider *"Real World Transaction Loss."* Arbitrage revenue is therefore *"Real World Transaction Gain."* and the initial filing's value of $103 million worth of revenue from the DA/RT volume component was the artificial arbitrage revenue that was in excess of any reasonable metric.

Q. With this as context, please explain how the error in the DA/RT volume component was corrected.

A. Whenever the monthly sales revenue from a volume adjustment at a trading hub shows arbitrage revenue by exceeding the monthly purchase cost for the same amount of

[103] Supplemental Direct Testimony of Ramon J. Mitchell at 6 (Correction 5) (RMP Exhibit 10.4).

volume in the same time period at the same trading hub, the formulaic pricing of the DA/RT volumes was corrected such that: (1) both the monthly sales revenue and the monthly purchase cost offset for no net impact to the NPC forecast; and then 2) the monthly sales revenue is adjusted upwards to re-introduce real arbitrage revenues from the historical data into the NPC forecast. This averaging to create a single price adjustment for both sales and purchases to remove *artificial* arbitrage revenue is identical to the adjustment calculated in the DA/RT price component to remove in-model artificial arbitrage opportunities.

Q. Turning to WIEC's Confidential Figure BGM-6,[104] please explain why WIEC's analysis misses the mark.

A. WIEC's Confidential Figure BGM-6 displays *"Real World Transaction Loss"* from 2017 to 2022. Then, in 2024, WIEC displays: (1) the **sum** of *"Perfect Foresight Transaction Loss"* and the NPC impact from the NPC Update that represents the *"Artificial Arbitrage Revenue"* in the "AURORA DA/RT" column; and (2) *"Perfect Foresight Transaction Loss"* in the "AURORA w/o DA/RT**" column. In this way, WIEC's figure displays three separate pieces of data that are not the same things.

That is to say, WIEC's Confidential Figure BGM-6 displays total actual historical net cost incurred when day-ahead or real-time market transactions are executed at prices unfavorable to the OFPC—along with all the real-world attendant inefficiencies, and then compares that <u>first</u> to the sum of two things (the "AURORA DA/RT" column): (1) the total net cost incurred from forecast hourly in-model transactions that are executed at prices unfavorable to the OFPC but result from perfect

[104] Direct Testimony of Bradley G. Mullins at 45 (WIEC Exhibit No. 202).

foresight and otherwise perfect efficiency; and (2) artificial arbitrage revenue, which is a negative value, but WIEC opportunistically shows it as a positive value. And then second, WIEC compares that to a meaningless number (the "AURORA w/o DA/RT**" column) that reflects the differences between an hourly scaled price curve and a flat monthly price curve after considering that WIEC removed the trading inefficiency from Aurora and attempts to argue that perfect foresight and perfectly efficient transactions (i.e., the removal of the DA/RT price component) that do not reflect the Company's actual operations are accurate expectations of the Company's actual operations in the test period.

Q. Have you corrected WIEC's Confidential Figure BGM-6 to display appropriately matched data?

A. Yes. As mentioned above, WIEC's Confidential Figure BGM-6 is misleading in comparing: (1) the sum of *"Perfect Foresight Transaction Loss"* and the inverse of *"Artificial Arbitrage Revenue"*; with (2) *"Real World Transaction Loss"* and then a meaningless perfectly efficient transaction value (the "AURORA w/o DA/RT**" column). That comparison is inapt, however, so Confidential Figure DART-5 below displays *"Real World Transaction Loss"* from 2017 to 2022 and then proxies 2023 to 2024 based on extrapolation.

Confidential Figure DART-5

[redacted]

Confidential Figure DART-6 below displays *"Perfect Foresight Transaction Loss"* and is the item that WIEC labels as "Impact of the Price Adjustment in Aurora" in their Confidential Figure BGM-6.

Confidential Figure DART-6

[redacted]

Lastly, the *"Artificial Arbitrage Revenue"* is the thing that was corrected in the

DA/RT volume component and does not belong in WIEC's Confidential Figure BGM-6 at all. However, for the sake of consistency I replicate it in its appropriately isolated context below in Confidential Figure DART-7. Now the data is in the appropriate figures and given the appropriate signage. Please note that I have ignored WIEC's column titled "AURORA w/o DA/RT**" because it represents the differences between an hourly scaled price curve and a flat monthly price curve after considering that WIEC removed the trading inefficiency (DA/RT price component) from Aurora and attempts to argue that perfect foresight and perfectly efficient transactions that do not reflect the Company's actual operations are accurate expectations of the Company's actual operations in the test period.

Confidential Figure DART-7

[redacted]

These three figures above appropriately provide definition, context and correction of WIEC's Confidential Figure BGM-6 and it is disingenuous and confuses the reader to combine all three charts into one. With the above as context, WIEC's corresponding analysis that the "DA/RT method modeling change presented in the July

Update, . . . increases the cost to $193,961,712"[105] is, first, false; second, mischaracterizing the correction as a modeling change; and third opportunistic and one-sided in seeking benefits without recognizing costs by outright ignoring: (1) the Company's change to the modeling of thermal generation marginal costs which decreases NPC by $75 million and **is** a modeling change; and (2) the Company's change to the modeling of OTR NOx allowance aggregation which decreases NPC by $144 million and **is also** a modeling change. WIEC's remaining analysis on the DA/RT and arguments as to why the DA/RT price component and DA/RT volumes are unnecessary is invalidated by their false analysis and rebutted further above.

Q. WIEC claims that "if the DA/RT price adjustment is removed completely, the AURORA model produced an implicit DA/RT adjustment of [redacted], which is generally in line with the historical data."[106] How do you respond?

A. If one assumes that WIEC's portrayal of the data and associated arguments are accurate, then after updating WIEC's charts with recent historical data, WIEC's argument is now that [redacted] is "in line" with that updated historical data. Please refer to my Confidential Figure DART-8 below which visualizes this [redacted] "in line with the historical data." This figure is simply an update to WIEC's Confidential Figure BGM-6 with the most recent historical data. From this visualization, trends from the prior figures, and market conditions and operational / policy changes limiting generation in the 2024 forecast, it is evident that WIEC's arguments fall flat and are invalidated.

[105] Direct Testimony of Bradley G. Mullins at 46 (WIEC Exhibit No. 202).
[106] *Id.*

Confidential Figure DART-8

[redacted]

Q. WIEC claims that removing the price component is a "subtle change" to the DA/RT adjustment that "lowered the NPC forecast by $17,141,121, with $2,356,829 allocated to Wyoming."[107] How do you respond?

A. WIEC's testimony mispresents the true impact of its supposedly "subtle change." As discussed above, WIEC's calculation of its adjustment reflected in Table BGM-1 is the result of a sequential analysis of all of WIEC's adjustments, which, as Mr. Mullins' own prior testimony explained,[108] distorts the individual line-item impacts based on the order in which the model runs are conducted and does not show the true cost impact of any NPC change but for the first line-item.

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[107] *Id.*, at 47.

[108] OPUC Docket No. UE 416, Opening Testimony of Bradley G. Mullins at 36 (AWEC/100).

Q. What is the isolated NPC impact of WIEC's DA/RT proposal—which WIEC claims to be $17 million total-Company, $2.4 million Wyoming-allocated?[109]

A. WIEC's adjustment on a stand-alone basis reduces NPC by $87 million total-Company, $12 million Wyoming-allocated.

Q. WIEC claims the Company's testimony in the 2015 rate case explained that the purpose of the DA/RT volume component is "to ensure that 'the overall cost of the Company's day-ahead and real-time balancing transactions relative to the forecasted monthly market prices [was] equal to the historical average.'"[110] Is this an accurate statement?

A. No. WIEC is misrepresenting the Company's position in the 2015 rate case. The Company clearly stated that "[t]hese [DA/RT] volumes are priced such that the overall cost of the Company's day-ahead and real-time balancing transactions relative to the forecasted monthly market prices [was] equal to the historical average".[111] The Company did not testify that the *purpose* of the DA/RT adjustment was simply to tie the forecast to the historical average values, which is a key distinction that WIEC misrepresents.

Q. Why is WIEC's misrepresentation of the purpose of the DA/RT volume component relevant in this case?

A. WIEC claims that the Company's NPC update included "an entirely new modeling adjustment to the DA/RT method."[112] WIEC is incorrect; the Company corrected the formulaic pricing of the DA/RT volumes because the results being produced in the

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[109] Direct Testimony of Bradley G. Mullins at 47 (WIEC Exhibit No. 202).
[110] *Id*., at 41.
[111] Docket No. 20000-469-ER-15 (Record No. 14076), Direct Testimony of Gregory N. Duvall at 32.
[112] Direct Testimony of Bradley G. Mullins at 42 (WIEC Exhibit No. 202).

initial filing were clearly erroneous and inconsistent with the purpose of the DA/RT volume component.

Q. How was the pricing of the DA/RT volumes producing erroneous results?

A. I have discussed details above but will reiterate at the conceptual level. First, it is important to establish the purpose of each of the two components of the DA/RT adjustment. As discussed above, the purpose of the DA/RT adjustment is to more accurately capture the true cost of balancing the Company's system in the short-term markets by: (1) adjusting forward market prices (the OFPC) to reflect variations between the average market-indexed prices over each month and actual realized prices for the Company's day-ahead and real-time transactions in that month (***price component***); and (2) adjusting system balancing transaction volumes to reflect the inefficiencies and associated costs of the operational practice of transacting on a monthly basis using, as an example**,** standard 25-MW increment, 16-hour block products, rebalancing on a daily basis using standard 25-MW increment eight-hour block products, and finally closing the remaining position on an hourly basis in real-time markets (***volume component***).

In the initial filing, the DA/RT volume component produced a $103 million revenue. However, the DA/RT volume component adjusts system balancing transaction volumes to reflect the *inefficiencies* and associated *costs* incurred in actual operations. A calculation that is designed to simulate *costs* associated with real-world trading *inefficiencies* but produces substantial ($103 million) and unrealistic *revenue* is clearly producing an erroneous result.

Q. WIEC claims that "the out-of-model volumes included in the NPC report were perfunctory" and so WIEC removed them.[113] How do you respond?

A. I have discussed above that the DA/RT volumes are necessary to address volumetric inefficiencies in trading and to produce a level of NPC forecast volumes that are a reasonable and accurate expectation of the test period volumes which come with attendant inefficiencies. In the following section I further demonstrate why the DA/RT volumes are reasonable and necessary.

X. MARKET CAPACITY LIMITS

Q. Please explain why Aurora requires market caps.

A. Like GRID, Aurora operates with perfect foresight and assumes unlimited market depth and full liquidity for the markets in which the Company makes off-system sales, unless informed otherwise. Aurora would therefore allow unrealistic off-system sales at every market at any time of the day or night—an assumption that is very different from the Company's actual, historical experience. In this case, the Company made no changes to its average of averages market cap modeling approved by the Commission in the 2020 GRC.

Q. Please describe WIEC's recommendation related to the Company's modeling of market caps.

A. WIEC proposes two changes to market caps. First, WIEC recommends increasing the caps at all hubs using a 95th percentile approach.[114] Second, WIEC removes market caps from Mid-C, Palo Verde, and Four Corners.[115] WIEC quantifies the impact of its

[113] *Id*., at 47.
[114] *Id*., at 53.
[115] *Id*., at 51.

adjustments in Table BGM-1;[116] however, for the reasons discussed above, WIEC's quantification is misleading because of its sequential modeling.

Q. WIEC claims that "the AURORA model lacks capability to evaluate off-system sales altogether" and it is "only by means of complicated modeling workarounds that [Rocky Mountain Power] was even able to incorporate off-system sales[.]"[117] Is this true?

A. No. The functionality that enabled GRID to evaluate off-system sales is identical in concept to the functionality that enables Aurora to evaluate off-system sales. The difference between the two models is that GRID's functionality was hidden in black-box code, whereas Aurora's functionality is modeled by the Company and visible to the parties. Furthermore, Aurora offers more flexibility to evaluate off-system sales because, unlike GRID, Aurora's functionality is editable by the user through a graphical user interface.

The Company also disagrees with WIEC's characterization of the method by which Aurora evaluates off-system sales, which WIEC describes as "modeling workarounds" because it is: (1) a modeling technique (not workaround); and (2) an accurate representation of how the market is perceived by the Company. From the Company's perspective, an electricity market *sale* at a trading hub is mostly a large pool of unspecified load which is served when the Company's generation displaces another unspecified utility's generation. That is to say, for the majority of market *sales* made by the Company, the load(s) that those market sales serve and the corresponding generator that the Company displaces is unknown at the moment of transaction. What

[116] *Id.*, at 7.
[117] *Id.*, at 48.

WIEC dismissively refers to as "displacement of fictionalized loads"[118] is more accurately described as "displacement of unknown load" and is precisely what's modeled in Aurora and is appropriate. Similarly, from the Company's perspective, an electricity market *purchase* at a trading hub is essentially a large pool of unspecified generation from unknown utilities that serve the Company's load by displacing the Company's own generators. That is to say, for the majority of market purchases made by the Company, the generators from which those market purchases are sourced are unknown at the moment of transaction.

Q. WIEC references the 2014 GRC and claims that the markets at Mid-Columbia, Palo Verde and Four Corners are "liquid" markets and therefore require no market caps.[119] Please explain what a liquid market is in the industry of today.

A. From the perspective of market sales, a liquid market is a market where the Company is able to find a buyer to take its excess energy at or above cost at almost all hours of almost all days.

Q. What then are market capacity limits?

A. Market capacity limits refer to the amount of energy that other market counterparties are willing to purchase in aggregate from the Company. More specifically, market capacity limits represent a threshold above which no one else can be found in the bilateral electricity markets to take the Company's energy at or above the Company's cost of producing that energy.

[118] *Id*., at 48.
[119] *Id*., at 51.

Q. Is it true that the markets at Mid-Columbia, Palo Verde and Four Corners are "liquid" markets for the Company?

A. No. Highly liquid market hubs no longer exist for an electric utility that is the Company's size at the Mid-Columbia and Palo Verde markets. As demonstrated in Confidential Figure CAPS-1 below, the volume of Company sales have been in constant decline for over five years, and energy shortfalls have increased across the region.[120] This exacerbation of energy shortfalls is demonstrated by the increased frequency of NERC reliability flags. The average duration of the highest level of energy emergency alerts (EEA 3) in 2022 was more than 200 minutes, exceeding the average duration for EEA alerts in previous years by almost double.[121]

While it may have been the case that some market hubs were liquid a few years ago, it is no longer the case now, as demonstrated below.

[120] North American Electric Reliability Corporation, *2022 Long-Term Reliability Assessment* at 11 (Dec. 2022) (available at-https://www nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf) (last visited Sept. 18, 2023).

[121] Western Electricity Coordinating Council, *State of the Interconnection 2023* at 5 (Mar. 24, 2023), *available at* - https://www.wecc.org/Administrative/State%20of%20the%20Interconnection.pdf.

Confidential Figure CAPS-1

[redacted]

Q. Is the Company's experience unique?

A. No. The volume of transactions in regional wholesale markets has been steadily declining in recent years. This decline is evident by examining data from the Intercontinental Exchange ("ICE"), which is one of the primary platforms used to trade energy on a day-ahead basis in the western interconnection. Data from ICE at the Mid-Columbia trading hub over the heavy load hours ("HLH") show that trading volumes have been consistently trending downwards over the past five years, from 2018 to 2022. Because a trade requires two counterparties, a buyer and a seller, a decrease in trading volumes year over year implies lower market sales volumes year over year across the Mid-Columbia region[redacted]. This ICE data is illustrated in Confidential Figure CAPS-2.

Confidential Figure CAPS-2

[redacted]

Q. WIEC states that the Four Corners market hub is liquid and that "[i]n 2022, for example, [Rocky Mountain Power] made [redacted] of short-term sales at the Four Corners market, which was far greater than any other market."[122] Does this single figure demonstrate that the Four Corners market is now a liquid trading hub?

A. No. When compared to the Company's total retail sales volumes of 66,639,713 MWh in the 2024 test period, [redacted] of sales at Four Corners does not demonstrate

[122] Direct Testimony of Bradley G. Mullins at 51 (WIEC Exhibit No. 202).

it is a liquid market. Moreover, the updated sales volumes for 12 months ending June 2023 are [redacted], which shows that sales at Four Corners are following the generally declining trend.

Q. WIEC takes issue with the Company's usage of the longstanding average of averages method for calculating market capacity limits by claiming that "using an average to set a maximum level of sales will result in a level of sales that is less than the historical average."[123] Is this claim true?

A. No. While that math may work in an academic context, it does not apply to the Company's modeling of NPC. The market capacity limits are calculated using four years of historical sales volumes inclusive of bookout transactions, which are equal and offsetting purchases and sales. The market capacity limits are then applied to sales in Aurora, which does not model bookouts. WIEC's mathematical relationship is arguably correct only if the caps are set without accounting for bookout volumes.

Q. WIEC claims that the Company uses a sample of "four data points" to calculate the market capacity limits.[124] Is this an accurate representation of the method?

A. No. WIEC's testimony is misleading—each of the "four data points" referenced by WIEC is calculated using 12 months of historical transactional data. In other words, there are up to 8,760 hours of actual energy interchange underlying the data used to calculate the average of averages market caps.

[123] *Id*., at 52.
[124] *Id*., at 53.

Q. WIEC creates a purported "95th percentile" liquid hub method of calculating market caps and justifies its reasonableness with Figure BGM-7, which purports to show their method being more "in line with the historical data."[125] Are there any issues with WIEC's analysis and conclusions?

A. Yes. There are four issues that: (1) invalidate WIEC's analysis; and (2) invalidate WIEC's claim of this 95th percentile liquid hub method being reasonable.

Q. What is the first issue?

A. First, WIEC has removed the DA/RT volumes from the model and this produces inaccurate levels of market sales. WIEC's Figure BGM-7 has no transaction volumes from the DA/RT volume component, which are a proxy for the additional volumes in the NPC forecast that would result if Aurora did not optimize using a single step, or, put another way, the DA/RT volume component and associated volumes reflects the reality that the Company balances its system over multiple time horizons and purchases and sells using multi-hour block products of energy in 25 MW increments. The additional sales volumes calculated by the DA/RT adjustment in conjunction with the Aurora modeled sales volumes combine to produce an outcome that together represents a more reasonable expectation of volumes to be incurred in the test period.

Without the DA/RT volumes, the result is an output from Aurora which executes transactions on an hourly basis[126] to within fractions of a megawatt with perfect foresight and perfect efficiency. This kind of output which WIEC relies on has

[125] *Id.,* at 54.
[126] The majority of Company transactions are multi-hour block (16- or 8-hour) transactions with a flat energy profile across the time period and the entire block trades in increments of 25 MW.

zero merit and is factually inaccurate because the Company's actual operations does not function in this perfect manner.

Q. What is the second issue?

A. The left-hand chart in WIEC's Figure BGM-7 excludes DA/RT volumes from the forecast results (column "RMP" and column "WIEC") and then compares those Aurora volumes without DA/RT volumes to the actual historical volumes with DA/RT volumes. This comparison is invalid, it compares two separate things.

WIEC attempts to justify this by implying that DA/RT volumes are all bookouts,[127] however WIEC provides zero evidence of this and, regardless, it is incorrect.

Q. Why is it incorrect to claim that the DA/RT volumes are all bookouts, as WIEC implies here?

A. System balancing transaction volumes must reflect the inefficiencies and associated costs of the operational practice of transacting on a monthly basis using, as an example, standard 25-MW increment, 16-hour block products, rebalancing on a daily basis using standard 25-MW increment eight-hour block products, and finally closing the remaining position on an hourly basis in real-time markets. The DA/RT adjustment of system balancing transaction volumes imputes what the volumes in the NPC forecast would be if the forecast was not perfectly optimized in a single step and instead optimized over multiple time horizons using the purchase and sale of multi-hour block products of energy in increments of 25 MW. Bookouts, on the other hand, are available when the Company holds offsetting positions (purchase and sale) for the same delivery

[127] As evidenced by their workpapers which calculate test period bookouts as all the DA/RT volumes.

point, in the same hour, with the same counterparty. (1) Aurora does not model bookouts within the model and so there are no bookouts in the Aurora results; and (2) the DA/RT volumes (MWh) are extrapolated solely from those Aurora results and does not contemplate counterparties.

Moreover, WIEC's own Confidential Figure BGM-7 displays two figures, and the figure on the right clearly shows that bookouts are only a fraction of the total historical sales volumes and the figure shows that bookouts are decreasing over time, similar to overall off-system sales volumes as illustrated in Confidential Figure CAPS-1 and the resulting market caps. This result is not surprising—with less market sales volumes there are less sales to bookout.

Q. If the Company were to account for bookouts, as the right-hand chart in WIEC's Figure BGM-7 purports to do, what does the data show?

A. Using WIEC's workpapers, I created a business-as-usual NPC scenario to appropriately compare 2024 sales volume to historical sales volumes, extrapolated the yearly ratio of "sales volumes with bookouts" to "sales volumes without bookouts" and then applied that ratio to the DA/RT volumes derived from using WIEC's "95th percentile liquid hubs" methodology. The results show that after adjusting for WIEC's claim of bookouts being present in the NPC forecast, the NPC forecast produced [redacted] of sales volume, which is above the 2019, 2020, 2021 and 2022 sales volumes shown on the left-hand chart of WIEC's Figure BGM-7 and well above the [redacted] evidenced in Confidential Figure CAPS-1.

Q. What are the third and fourth remaining issues?

A. Third, all the columns in the right-hand chart of WIEC's Figure BGM-7 purport to have either bookouts or the DA/RT volumes included—except for the "WIEC" column, which has neither. WIEC's analysis therefore does not provide for a very meaningful comparison.

Fourth, in both charts of WIEC's Figure BGM-7, WIEC calculates the "RMP" column based on the outdated inputs from the initial filing but yet calculates the "WIEC" column based on the up-to-date inputs from the NPC Update and in doing so makes an inapt comparison.

Q. Can you correct the errors in WIEC's Figure BGM-7 and update the figure to allow for a meaningful comparison of historical and forecast off-system sales?

A. Yes. First, I put the DA/RT volumes back in; as discussed above they are necessary to reflect the realities of actual operations.

Second, I reflected a declining trend in bookouts, consistent with the general declining trend in both bookouts and market volumes.

Third, I removed the "WIEC" column given that its results were flawed, for the reasons discussed above.

Fourth, my analysis was based on a business-as-usual scenario which excludes the myriad of operational changes included in the 2024 NPC forecast that are not present in the historical data, such as coal supply limitations, the OTR, the Jim Bridger gas conversion and associated outage, the removal of the Klamath dams, and the Washington Cap and Invest Program.

Fifth, for illustrative purposes, I visualized a proxy of 2023 sales volumes by using the first seven months of actual 2023 sales volumes and ratioing them out to twelve months. This proxy is not a business-as-usual case and I use it below only to support the use of the average of averages method.

Sixth, I have updated all numbers to be consistent with the NPC Update.

Seventh, I have now corrected and re-visualized WIEC's proposed 95th percentile liquid hubs approach to again demonstrate its unreasonableness. The visualization below in Confidential Figure CAPS-3 is that corrected and updated version of WIEC's erroneous analysis. The right-hand chart is still in error regarding bookouts, as discussed above.

Confidential Figure CAPS-3

[redacted]

Q. Have you also prepared a correction of WIEC's analysis that includes the impact of the operational changes present in 2024?

A. Yes. For comparison purposes, I have corrected WIEC's Figure BGM-7, updated it with an extrapolation of a declining trend of bookouts, updated it with the proxy of 2023 data and present it below. This Confidential Table CAPS-4 below includes the operational and policy changes that will impact 2024 in the "RMP" column and is therefore simply a correction and update to WIEC's Confidential Figure BGM-7 and the chart on the left (which uses the method that WIEC prefers) still shows that **even with the myriad of operational and policy changes**, the 2024 sales volume for the "RMP" column using the longstanding average of averages method is above the 2021 sales volume, above the 2022 sales volume, above the 2023 extrapolated sales volumes, and well above the [redacted]. The right-hand chart is still in error regarding bookouts, as discussed above.

Confidential Figure CAPS-4

[redacted]

Q. After all these corrections and updates, what do the results show?

A. WIEC's method produces extremely high and unreasonable levels of forecast market sales volumes which are greater than the past four years of actual sales volumes. The longstanding average of averages method produces a result that, although excessive when compared to the declining trend in off-system sales volume, is far more reasonable. These results are illustrated in the left-hand chart of Confidential Figure CAPS-4, which is WIEC's preferred comparison.

XI. AMBIENT DERATES

Q. Please explain WOCA's proposed adjustment to the ambient temperature derates.

A. WOCA claims that the "maximum capacity was undervalued in NPC modeling" for the Currant Creek, Lakeside 1, Lakeside 2, and Wyodak plants.[128] WOCA therefore proposed an adjustment to decrease NPC $30 million on a total-Company basis.[129]

Q. How do you respond to WOCA's adjustment?

A. WOCA's adjustment is flawed for three reasons.

Q. What is the first issue with WOCA's adjustments on these thermal plants?

A. Currant Creek is a combined cycle gas plant with two combustion turbines, a steam turbine (collectively referred to as the "2x1 operation") and the ability to burn natural gas within the ducts (duct firing operation) for approximately 100 MW of additional capacity. In the Aurora model, the 2x1 operation is modeled separately from the duct firing operation. WOCA increased the aggregate capacity of the 2x1 operation to include capacity from the duct firing operation while keeping the duct firing operation within the model and so double counted capacity. This is evidenced by the fact that after WOCA's modeling adjustments the Currant Creek plant is now capable of generating up to 576 MW in the month of July,[130] which is greater than its net dependable capacity[131] of 550 MW. WOCA appears to have made the same double

[128] Direct Testimony of Colin T. Fitzhenry at 16 (WOCA Exhibit No. 603).
[129] *Id*.
[130] As per WOCA's Aurora project.
[131] Net dependable capacity is the net maximum MW output a unit or configuration can sustain over a specified period of time when not restricted by ambient conditions or deratings. This unit rating may change only as a result of a new performance test or permanent unit modification and can never be changed due to equipment problems, even if they persist for a lengthy period of time, unless the unit is permanently modified as a result.

count error at Lakeside 1 and at Lakeside 2, which both also have 2x1 operations and duct firing operations.

Q. What is the second issue with WOCA's adjustments on these thermal plants?

A. WOCA applies the same (identical) capacity across the months of June, July, and August.[132] However, temperatures are indisputably higher on average during July than June (as an example) and Exhibits 10.8 and 10.9 demonstrate the degradation in generation capacity that results from increased temperatures. The exhibit graphs were provided to the Company by the General Electric Company and by Siemens Energy AG to demonstrate this engineering fact.

Q. What is the third issue with WOCA's adjustments on these thermal plants?

A. WOCA relied on data provided by the Company for the Wyodak coal plant,[133] and the data provided to WOCA was the Wyodak total-plant capacity. However, the Company only owns 80 percent of Wyodak and this means that the Company can only receive 80 percent of the total-plant capacity. WOCA's Excel workpapers appear to show the use of 100 percent of the total-plant capacity.

Q. In light of these issues, what is your conclusion regarding WOCA's adjustments and corresponding reduction to NPC of $30 million, total-Company?

A. WOCA's adjustments are in error and so is the calculated reduction to NPC. As demonstrated in the Company's workpapers and the attached exhibits: (1) the capacities at these thermal units degrade during the summer months, this is an established engineering fact; (2) the Company's modeling of this degradation, which is referred to as ambient derates within the industry, is both factual and appropriate; and (3) the

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[132] Direct Testimony of Colin T. Fitzhenry at 16 (WOCA Exhibit No. 603).
[133] *Id.*

Company's NPC proposal in my supplemental direct testimony presents the accurate NPC impact of ambient derates.

XII. JIM BRIDGER OUTAGE

Q. WOCA proposes to disallow, in this GRC, the known and measurable cost of the Jim Bridger outage required for gas conversion.[134] They then propose that in the 2025[135] ECAM, the "cost of the outage should be calculated and not subject to the sharing band."[136] How do you respond?

A. The Company is amenable to this proposal as stated in Section I.

XIII. COAL PRICING

Q. WOCA recommends reductions in coal contract prices until the Company "provides further information regarding its coal contract prices."[137] How do you respond?

A. Please refer to the rebuttal testimony of Company witness Mr. Owen for details on the increases in Company coal contract prices. Company witness Mr. Owen provides the necessary justifications, and as a result WOCA's $36 million reduction in NPC is no longer valid.

XIV. THIRD-PARTY RESERVES

Q. Please describe WIEC's adjustment related to the Company's obligation to provide reliability reserves to non-native (third-party) generators and utilities.

A. To maintain a reliable system and to comply with its obligation to provide certain ancillary services to third-party customers under the Company's Open Access

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[134] *Id*., at 17.
[135] This ECAM will look back at calendar year 2024.
[136] Direct Testimony of Colin T. Fitzhenry at 17 (WOCA Exhibit No. 603).
[137] *Id*., at 17-18.

Transmission Tariff ("OATT"), the Company provides reserves for reliable and safe electric service for all load located within its Balancing Authority Area ("BAA"). The Company collects revenue for this service in accordance with rates approved by FERC and credits those revenues to retail customers in Wyoming. WIEC contends that the Company is not collecting sufficient revenues from these third-party customers and therefore recommends a disallowance of $210,694,263 on a total-Company basis, or $28,969,536 on a Wyoming-allocated basis.[138]

Q. Is WIEC's adjustment reasonable?

A. No. As explained in detail in the testimony of Company witness Amparo Nieto, WIEC's recommendation is contrary to cost-based ratemaking at both the state and federal level. In addition, as I discuss below, WIEC's modeling of third-party reserves is flawed, which further undercuts the credibility of its recommendation.

Q. As an initial matter, is the provision of reserves to third-party customers necessary to ensure reliable service to Wyoming customers?

A. Yes. The Company is required to hold certain levels of reserves to comply with reliability standards mandated by the NERC. In particular, and as explained in further detail by Company witness Michael G. Wilding, the Company is mandated to hold contingency reserve requirements under NERC standard BAL-002-WECC-3, mandated to hold regulation reserve requirements under NERC standard BAL-001-2, and mandated to hold frequency responsive reserves (a subset of regulation reserves in the NPC modeling) under NERC standard BAL-003-2. There is no option to **not** hold the entirety of these reserves for the entire balancing area, which includes third-party

[138] Direct Testimony of Bradley G. Mullins at 66 (WIEC Exhibit No. 202).

generation and load. The last instance of severe reserve failure to maintain reliability of the Company's transmission grid, and by extension the reliability of neighboring utilities, resulted in a $3.9 million fine for an approximate two-hour violation.[139]

If the Company held insufficient reserves and thereby violated the NERC reliability standards, then it would create reliability issues throughout its BAAs that would adversely affect Wyoming customers. In other words, refusing to hold sufficient reserves for some customers does not isolate other customers from the reliability impacts to the BAA as a whole. Therefore, the provision of reserves to non-retail, third-party customers provides a direct and significant benefit to Wyoming customers.

Q. On the modeling front, WIEC claims that the "AURORA model is not configured to evaluate reserves for non-native loads and resources" and the Company "used a workaround where it added in the requirements of non-native load and generation, but correspondingly offset the modeled requirements with fictitious purchases and sales."[140] Is this true?

A. No. WIEC once again misunderstands the Aurora modeling. As an initial matter, the third-party generation and loads are modeled on islands, and these islands have no transmission connectivity to the rest of the Company's system. WIEC is apparently unaware of this modeling fact and therefore inaccurately speculates that the modeling of these third-party resources "may have impacted the zonal clearing prices for generation, causing uneconomic dispatch, and increasing the incremental cost of

[139] *In re PacifiCorp*, 137 FERC 61,176, Order Approving Stipulation and Consent Agreement at 15 (Dec. 1, 2011) (available at https://www.nerc.com/pa/comp/CE/Enforcement%20Actions%20DL/OrderApprovingStipAgrmt-PacifiCorp_IN11-6_20111201.pdf) (last visited Sept. 18, 2023).

[140] Direct Testimony of Bradley G. Mullins at 66 (WIEC Exhibit No. 202).

holding reserves for non-native services."[141] This is simply inaccurate. Please refer to the below Confidential Figure RES-1 for a visualization of this topology wherein third-party (non-owned) load and generation is not connected to the Company's system.

Confidential Figure RES-1

[redacted]

WIEC's claim that the Company used a "workaround" is also simply inaccurate and again demonstrates WIEC's lack of understanding of Aurora. The third-party load and generation are modeled on their islands as load and as generation, and then Aurora itself includes a feature that directly offsets the energy impact of these resources without the need for any modeling "workaround". WIEC's recommendation is premised on its misunderstanding of Aurora modeling and therefore has no merit.

Q. Has WIEC correctly calculated the NPC impact of providing these reserves to third-party customers?

A. No. There are three errors associated with WIEC's calculation, each of which results in an apparently coincidental reduction to NPC as compared to what the reduction

[141] *Id.*

would have been had the calculations not contained errors.

Q. What is the first error?

A. First, as discussed above, WIEC calculates the NPC impact of this adjustment within a sequential change log (WIEC's Table BGM-1) where the impact of the third-party reserve adjustment is the last change in the log.[142] Therefore, the NPC impact of the third-party reserve adjustment is dependent on all of the other modeling adjustments that precede it. As discussed in Section III above and in WIEC witness Mr. Mullins' prior testimony, using a sequential change log results in the NPC "impacts skewed by the order in which the adjustment calculations were performed."[143] WIEC's testimony therefore does not provide the true NPC impact of this adjustment on an isolated basis.

Q. What is the second error?

A. Second, in removing the third-party generation and load from the regulation reserve templates, WIEC inadvertently and incorrectly adjusted the regulation reserve study itself by assuming that the study was conducted at the system level instead of the balancing authority area level. If it were WIEC's intention to adjust the regulation reserve **study** instead of simply adjusting the **inputs**, then WIEC may have failed to realize that the study is not the result of two 40-megabyte Excel files (which are the files WIEC incorrectly adjusted) but the result of an extensive programming exercise which is over 800 megabytes in size.[144]

After correcting these two errors, the NPC impact becomes a decrease of $125 million total-Company, or $18 million Wyoming-allocated. This is in stark contrast to

[142] *Id.*, at 7.
[143] OPUC Docket No. UE 416, Opening Testimony of Bradley G. Mullins at 36 (WIEC/100).
[144] This 800 megabyte programming exercise was provided to WIEC as part of the discovery process but WIEC did not adjust anything in that programming exercise.

the $211 million total-Company, $29 million Wyoming-allocated, that WIEC claims as the NPC impact.[145]

Q. Why is the impact of WIEC's recommendation, as corrected, so high?

A. This relates to WIEC's third error. WIEC's adjustment relies on an erroneous calculation of the incremental opportunity cost of reserves, i.e., the cost of the last megawatt of reserves held, when the correct calculation requires use of the cost of all megawatts of reserves held. As an example, WIEC's calculation implies that reserves held for third-party load and generation are first served by using market purchases to free up capacity—meaning that the cost of reserves to third-parties is essentially the market value of generation that could have been sold if the Company were not required to hold reserves—while WIEC's calculation also implies that reserves held for Company load and generation are first served by using zero-NPC demand side management programs. However, neither of these bookend scenarios are true; the Company does not differentiate between the reserves held for retail load and the reserves held for third parties; necessary levels of reserves are held to serve customers through the entire system and determined on a system basis. By calculating its adjustment using the incremental opportunity cost of holding reserves, rather than the average cost, WIEC grossly overstates the impact of its recommendation, so even if its recommendation was reasonable, which it is not, the value of the adjustment is wrong.

Q. After correcting WIEC's three errors, what is the NPC impact of the portion of reserve requirements held for third-party load and generation?

A. I have taken WIEC's workpapers and corrected the analysis to derive the $/MWh

[145] Direct Testimony of Bradley G. Mullins at 66 (WIEC Exhibit No. 202).

associated with **all** reserve requirements, and then based on that price, calculated the NPC impact of the portion of reserve requirements held for third-party load and generation. The results show that the average opportunity cost of that third-party portion of the reserve requirements is $35 million total-Company, or $4.9 million Wyoming-allocated.

Q. Please explain why it is incorrect to value the reserves held for third-parties using the opportunity cost of reserves, as WIEC has done in its adjustment.

A. It is only reasonable to value the third-party reserves using an incremental opportunity cost if WIEC's proposal is that the Company stop holding the NERC-mandated reserves for third parties on dispatchable generation in actual operations from which the ECAM power costs are derived. If this is not WIEC's proposal, then the cost of reserves used in its adjustment cannot be derived from an incremental opportunity power cost modeling sensitivity because that study is a reflection of actual operations, where the reserves are actually held. Because WIEC calculated its adjustment on an opportunity cost basis, WIEC is calculating NPC on the premise that the Company stop holding the third-party NERC-mandated reserves on dispatchable generation in actual operations. In short, WIEC has calculated NPC by simply removing the NERC-mandated reserve requirements from the NPC forecast, which means that WIEC values the NPC impact of holding reserves as an opportunity cost of not having economic generation capacity available to serve customers or to sell into the wholesale market.

Q. Please further elaborate on why is it incorrect to value the Company's reserves using an opportunity cost, as WIEC has done in its adjustment?

A. OATT rates applicable to third-party load and generation are determined as prescribed by FERC based on the embedded costs of the Company's generating units used to provide the reserves, as described by Company witness Nieto. The result is that third-party load and generation pay for a portion of the capacity used to provide reserves, and this payment is credited back to the Company's retail customers through wheeling revenue. It is not appropriate to impute a reduction to NPC based on the difference between OATT revenue and an opportunity cost of holding reserves in the test period.

As a regulated electric utility, the Company is obligated to provide power and ancillary services to retail customers at embedded cost. As a balancing authority, the Company is obligated to provide ancillary services to transmission customers at embedded cost. In neither venue is the Company allowed to charge customers opportunity costs, as explained by Company witness Nieto. To provide these services to both retail and transmission customers, the Company effectively allocates a portion of its embedded resources to each group. A portion of the Company's generation resources are used to provide power and ancillary services to retail customers and a portion of the Company's generation resources are used to provide ancillary services to transmission customers.

Q. If the Company is required by FERC to provide service to wholesale customers is there an "opportunity cost" that the Company is choosing to forgo?

A. No. The definition of an opportunity cost is that it is the choice of one alternative over another and it is the value of the alternative that was forgone. Here, the Company is not making a choice—it is required by FERC to serve these customers and the opportunity cost that is foregone is the penalty that the Company would incur if it did not provide service. WIEC's argument of an opportunity cost relies on the premise that the

Company has an ability to stop holding these reserves and sell the freed up energy into the wholesale market. This is just not true.

Q. What is the practical effect of WIEC's proposed adjustment?

A. In effect, WIEC is proposing that the Company should charge OATT customers for the capacity held to integrate their load or generation *and* allow the same capacity to be used to make off-system sales to generate a margin to be credited back to retail customers. Because revenue from OATT customers is already passed back to retail customers through wheeling revenue, implementing WIEC's proposal would double count revenue.

Q. Does WIEC's recommendation also create disincentives for the Company in actual operations?

A. Yes. According to WIEC's own testimony, the ECAM is structured to encourage accurate modeling supporting the forecasted NPC baseline and to encourage the Company to use its best efforts to control costs in actual operations.[146] According to WIEC, the incentives are created by the ECAM sharing bands, which as currently structured return to or recover from customers 80 percent of the difference between actual and forecast ECAM costs, and the remaining 20 percent of the difference is retained or absorbed by the Company ("80/20 sharing band").

By reducing the NPC forecast to account for WIEC's perceived "costs in NPC that exceed the level of revenues,"[147] per WIEC's logic, the Company would be incented to increase the revenues from providing NERC-mandated reserve

[146] Direct Testimony of Kevin C. Higgins at 39 (WIEC Exhibit No. 200).
[147] Direct Testimony of Bradley G. Mullins at 65 (WIEC Exhibit No. 202).

requirements or to reduce the opportunity costs from providing NERC-mandated reserve requirements.

Q. Is it possible to increase the revenues from providing NERC-mandated reserve requirements to match the commensurate costs?

A. No. Company witness Nieto discusses in detail how FERC does not allow for opportunity costs (i.e, the loss of potential gain from other alternatives) to be used in the calculation of ancillary service rates, which reflect those reserves that are mandatory per NERC standards, subject to FERC oversight.[148]

Q. Is it possible to reduce the opportunity costs from providing NERC mandated reserve requirements to match the commensurate revenues?

A. Yes. It is possible to achieve NPC savings by sacrificing customer reliability. Reliability is heavily regulated and mandated by both FERC and NERC, but the Company has options that can be taken to save money on power costs at the expense of customer reliability. The Company does not advocate for or propose that the Commission adopt any such measures however, as the Company's guiding principles are to provide reliable and safe electric service to all customers.

Q. How can the Company reduce the opportunity costs from providing NERC-mandated reserve requirements to match the commensurate revenues?

A. Instead of holding these regulation and contingency reserve requirements on dispatchable generation—these reserves which WIEC has removed from the NPC forecast as part of their monetary adjustment—NERC allows for balancing authorities like the Company to hold these reserves on firm customer load. However, customer

[148] NERC is the Electric Reliability Organization for North America, subject to oversight by FERC.

reliability and safety are of the utmost importance to the Company, taking priority over power cost savings. It is extremely inappropriate for WIEC to produce these incentives to save on power costs by reducing the reliability and safety of Wyoming customers' electric service.

XV. THE ENERGY COST ADJUSTMENT MECHANISM

A. Background

Q. Please summarize the Company's ECAM sharing band proposal from its initial filing.

A. The Company proposed to eliminate the 80/20 sharing band within the ECAM.[149]

Q. Is the Company proposing a modification to this request in its initial filing?

A. No. The Company continues to propose eliminating the ECAM sharing band.

Q. Parties in this proceeding assert that the ECAM sharing band incentivizes the Company to control costs.[150] Is this true?

A. No. Among other things, the ECAM sharing band returns to or recovers from customers 80 percent of the difference between actual and forecast NPC, and the remaining 20 percent of the difference is retained or absorbed by the Company.[151] However, the

[149] Direct Testimony of Ramon J. Mitchell at 38-40 (RMP Exhibit 10.0).
[150] *See, e.g.*, Direct Testimony of Kevin C. Higgins at 39-40 (WIEC Exhibit No. 200) ("When a firm stands to gain or lose from its cost management decisions, as RMP does today under the ECAM, the pursuit of its economic self-interest gives it a powerful incentive to perform well in managing its costs."); Direct Testimony of Colin T. Fitzhenry at 23 (WOCA Exhibit No. 603) ("Maintaining the current 80/20 sharing band provides an important incentive for the Company to continue to properly manage its costs with respect to the functions that continue to be in its control.").
[151] *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 at 39 (July 15, 2021) (modifying the sharing bands to the current 80/20 sharing band).

forecast NPC from rate cases are not referred to or relied upon by the Company in its operation of the power system.[152]

That is to say, the forecast NPC is not relevant to the Company's power operations decisions. The forecast NPC is simply one static number put together at one single point in time based on predictions of the future. It would be both imprudent and impractical for the Company to rely on that single, static, forecast number to conduct power system operations and incur actual NPC when considering how quickly any forecast becomes stale in today's ever-changing, dynamic industry landscape.

In actual operations the Company is constantly updating market price forecasts, load forecasts, hydrologic forecasts, renewable forecasts, coal supply expectations, and transmission rights, among a multitude of other constantly changing factors, to effectively and prudently control NPC for the best outcome to customers. This incentive to control NPC is rooted in the need to maintain competitive operations, which is of particular relevance in Wyoming where the Company can compete for industrial load with customer-sited or customer-specific generation.

Q. If the ECAM sharing band does not incentivize the Company to control costs, then what does it do?

A. The ECAM uses the existing forecast mechanisms to encourage accuracy of modeling supporting the forecasts.[153]

[152] Absent WIEC's proposal, which implies a Wyoming-specific incentive to use Wyoming customer load as operational reserves to save on power costs as discussed in Section XIV.
[153] Docket No. 20000-368-EA-10 (Record No. 12477), Memorandum Opinion, Findings and Order at 23.

Q. How then is the Company actually incentivized to control costs and to avoid creating disadvantage for Wyoming customers?

A. Through judicious prudency review[154] and competition for customer load with customer sited / specific generation.

Q. Do you have any concerns with the ECAM's sharing band considering the aforementioned issues?

A. The ECAM was *designed* to provide incentives to the Company for four purposes,[155] and as I have discussed, only two of those purposes *actually* remain functional. A four-leg table is stable, but a two-leg table is not. Similarly, the ECAM, as it *actually* functions, is not stable and I propose that the Commission eliminate it in place of judicious prudency review.

Q. In 2011, did the Commission opine that a prudency review should not be the exclusive principle to consider power cost decisions?[156]

A. Yes. WIEC's testimony in that case persuaded the Commission. WIEC's arguments boiled down to their assertion that:

> [T]he threat of a finding of imprudence following an after-the-fact audit is not a good substitute for the company having skin in the game when it comes to **managing its costs** . . . In contrast, a risk sharing mechanism structured such that each and every action undertaken by

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[154] In which WIEC is actively engaged within the current 2023 ECAM, **in addition to** the automatic 20 percent disallowance of $18 million under the sharing band. *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 Pursuant to Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates by $1.5 Million (0.2 Percent) Pursuant to Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism*, Docket No. 20000-642-EM-23 (Record No. 17279), Direct Testimony of Jack Painter at 8 (RMP Exhibit 2.0).

[155] Docket No. 20000-368-EA-10 (Record No. 12477), Memorandum Opinion, Findings and Order at 23; *see also* Direct Testimony of Ramon J. Mitchell at 39 (RMP Exhibit 10.0).

[156] Docket No. 20000-368-EA-10 (Record No. 12477), Memorandum Opinion, Findings and Order at 22-23.

> the company affects its bottom line provides an **incentive** for the company to get the best possible result from every action.[157]

However, as I have discussed, the sharing band does not incentivize the Company's operational decisions (i.e., the actual incurring of net power costs). Therefore, 12 years later in an ever-changing, dynamic industry landscape,[158] WIEC's arguments are no longer valid.

Q. If the sole remaining function of the ECAM is to encourage accuracy of modeling supporting the forecasts, is it appropriate for the Company to retain or absorb 20 percent of the difference between actual and forecast NPC?

A. No. I discussed in my initial filing how the "[t]he resource mix across the **western interconnection**[159] has evolved from one dominated by controllable thermal generation to one dominated by intermittent weather-dependent generation. Specifically, coal and gas generation facilities are being retired and replaced with solar and wind generation facilities."[160] This "change in resource mix within the **western interconnection** decrease[s] NPC forecast accuracy."[161]

Q. Are there other changes within the industry that decrease NPC forecast accuracy?

A. Yes. The impending participation in a NPC-complete organized market (EDAM) will lower NPC but will worsen the current and ongoing inaccuracy in NPC modeling/forecasting.

[157] Docket No. 20000-368-EA-10 (Record No. 12477), Memorandum Opinion, Findings and Order at 15 (emphases added).
[158] Direct Testimony of Ramon J. Mitchell at 56-58 (RMP Exhibit 10.0).
[159] The western interconnection is the geographic area containing the synchronously operated electric grid in the western part of North America, which includes parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming and Mexico and all of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, Washington and the Canadian provinces of British Columbia and Alberta.
[160] Direct Testimony of Ramon J. Mitchell at 48 (RMP Exhibit 10.0) (emphasis added).
[161] *Id*., at 49 (emphasis added).

Q. How does the impending participation in a NPC-complete organized market worsen the current and ongoing inaccuracy in NPC modeling/forecasting?

A. The EDAM is not a Company-centric market. It is an organized market operated by the CAISO that may encompass a footprint spanning large swathes of the western interconnection and, to achieve greater efficiencies in cost controls and lower NPC for all participants/utilities, the CAISO will optimize the regional footprint as a single entity, at the nodal level, identical in concept to how the EIM currently operates across a wide regional footprint in its intra-hour optimization.

Q. How does the optimization of NPC across multiple utilities in the day ahead market further increase the difficulty of producing an accurate NPC forecast?

A. Currently, an accurate NPC forecast requires detailed knowledge of future generation conditions, transmission rights, load forecasts and other Company-operations-specific information. This information is mostly confidential by nature. With participation in the EDAM, the regional footprint across multiple utilities in the day-ahead timeframe at the hourly level is operated as a single system on a day-ahead basis.

To accurately model and forecast the Company's NPC it will now become necessary to obtain detailed knowledge on future generation conditions, transmission rights, load forecasts, etcetera, *as it relates to other utilities' operations*. This information is naturally also considered confidential from the perspective of these other utilities and the Company's NPC forecast will consequently lack the necessary information required to produce an accurate result.

Q. Can this missing modeling information, specific to other utilities, be proxied or inferred through publicly available information?

A. As it concerns other utilities, there is no publicly available information that could be considered a reasonably accurate replacement for confidential information such as planned generation outages, purchase of transmission capacity rights, the costs embedded in power purchase agreements for new resources, etcetera. These and other similar types of forward-looking information are considered confidential because they would provide a competitive advantage to other entities in the industry if the information were known. Since utilities still manage to retain competitive advantage, it is therefore a logical conclusion that there is no reasonably accurate replacement for this information, for if there were, the competitive advantage would have already been lost.

B. Reply to WIEC

Q. WIEC advocates for retaining a sharing band in the ECAM in large part because they view the sharing band as "[s]ending the right incentive for the Company to manage its costs[.]"[162] How do you respond?

A. While it is true that the ECAM as *designed* is an incentive mechanism for cost control, as mentioned above, it does not *actually* incentivize NPC control, only forecast accuracy. I have discussed the issues with forecast accuracy and noted the lack of stability in the ECAM's current "two-leg" functional incentives. WIEC has missed the mark in its assessment of the ECAM sharing band by ignoring how the utility actually operates.

[162] Direct Testimony of Kevin C. Higgins at 37 (WIEC Exhibit No. 200).

A substantial remainder of WIEC's testimony on the ECAM sharing band revolves around the presumption that NPC control is incentivized through this mechanism. Since their underlying presumption is inaccurate, I will not address that remainder of their testimony.

Q. What portions of WIEC's testimony are still relevant?

A. Under EDAM participation, WIEC notes that the Company is still responsible for things like plant maintenance, forced outages, resource sufficiency, hedging and reliability-related activities.[163] However, WIEC's arguments here are strong advocates for the use of judicious prudency review to replace the sharing band. Planned maintenance and forced outages are few in number, well documented, and easily accessible for review. Indeed, in the ongoing 2023 ECAM,[164] WIEC is actively engaged in prudency reviews and recommends disallowances totaling approximately \$21 million.[165] This is **in addition to** the automatic 20 percent disallowance of \$18 million under the sharing band.[166] That is to say, WIEC's prudency review in isolation[167] has already begun to accomplish the impact of the sharing band and this—in addition to my discussions further above and further below—advocates for judicious prudency review coupled with elimination of the sharing band.

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[163] *Id*., at 43-44.
[164] Applicable to calendar year 2022.
[165] Docket No. 20000-642-EM-23 (Record No. 17279), Direct Testimony of Bradley G. Mullins at 5 (WIEC Exhibit No. 200).
[166] Docket No. 20000-642-EM-23 (Record No. 17279), Direct Testimony of Jack Painter at 8, Table 1 (RMP Exhibit 2.0 (calculated as "Wyoming Allocated Actual Adjusted NPC" less "Actual Collections of Base NPC").
[167] The Wyoming Public Service Commission-Consumer Advocate Staff ("CAS") is also actively engaged in prudency review and their adjustments would increase WIEC's recommended \$21 million disallowance. Docket No. 20000-642-EM-23 (Record No. 17279), Direct Testimony of Michelle Bohanan at 3-4 (CAS Exhibit 301).

Q. How are planned maintenance and forced outage rates properly incentivized without a sharing band?

A. Planned maintenance and forced outages are few in number, well documented, and easily accessible for judicious prudency review.

Q. Please elaborate on the incentivization of hedging and resource sufficiency in the EDAM without a sharing band.

A. WIEC states that "as a participant in the EDAM, PacifiCorp will be required to bring sufficient resources to serve its load and ancillary services to each day-ahead."[168] These sufficient resources are primarily the Company's hedges, which WIEC asserts "will continue to have an impact on NPC even after the Company joins the EDAM."[169] WIEC's arguments on hedging have one fatal flaw. With a well-designed hedging program and policy in place, hedges are mostly unrelated to the ECAM. Hedging transactions and associated costs are designed to limit the risks and variability associated with market exposure and provide rate stability; they are not economic optimization transactions. That is to say, hedging transactions are not for the purposes of lowering NPC and controlling costs. Furthermore, hedging transactions are also few in number, their metrics are well tracked, and they are easily accessible for prudency review. To exemplify this fact, in the ongoing 2023 ECAM, WIEC has reviewed the Company's hedging and recommends hedging-specific disallowances totaling approximately $6.7 million.[170]

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[168] Direct Testimony of Kevin C. Higgins at 44 (WIEC Exhibit No. 200).
[169] *Id*.
[170] Docket No. 20000-642-EM-23 (Record No. 17279), Direct Testimony of Bradley G. Mullins at 5 (WIEC Exhibit No. 200).

Q. What about WIEC's concern on "reliability-related activities?"[171]

A. It is concerning, *to the Company*, that WIEC is discussing reliability in the context of controlling costs. The Company's guiding principles are to first and foremost provide reliable and safe electric service to all customers. Reliability and safety of electric service comes before cost control and the ECAM is not designed to save on power costs through sacrificing system reliability, contrary to WIEC's arguments in their NPC section of testimony,[172] and as I discussed above in Section XIV.

Q. With the above discussion as context, how do you assess WIEC's assertion that "part of the challenge of reviewing the prudence of PacifiCorp's NPC is that such a review requires examining thousands of transactions and decisions that are made every hour of every year?"[173]

A. As stated in my initial filing "With participation in an organized market, the quantity of transactions to review are less numerous because the majority of NPC transactions and decisions will be automated under the purview of an independent system operator. The remaining NPC transactions relevant for prudency reviews become smaller by magnitudes and therefore manageable instead of monumental."[174]

Q. Do you have any remaining comments on WIEC's ECAM sharing band arguments?

A. Yes, there are two. First, WIEC implies that I have attributed the increased difficulty in forecasting NPC to **the Company's** "changing mix of generation assets."[175] WIEC

[171] Direct Testimony of Kevin C. Higgins at 44 (WIEC Exhibit No. 200).
[172] Direct Testimony of Bradley G. Mullins at 63 (WIEC Exhibit No. 202).
[173] Direct Testimony of Kevin C. Higgins at 49 (WIEC Exhibit No. 200).
[174] Direct Testimony of Ramon J. Mitchell at 61 (RMP Exhibit 10.0).
[175] Direct Testimony of Kevin C. Higgins at 46 (WIEC Exhibit No. 200).

misrepresents my testimony. As I stated in my initial filing, "[t]he Company's portfolio of wind and solar resources is only approximately four percent of the total wind and solar capacity across the western interconnection. Had the Company not installed a single megawatt of wind or solar generation, the NPC forecast would still be driven by market prices and, therefore, still suffer from difficulties in forecast accuracy resulting from the region-wide adoption of these weather dependent resources."[176]

Q. What is your second comment on WIEC's ECAM sharing band arguments?

A. Second, WIEC asserts that "Wyoming's former 70/30 sharing mechanism was more favorable to shareholders than the power cost adjustment mechanisms in Oregon or Washington."[177] WIEC makes a particularly perplexing argument here. They take the regulatory and associated policy frameworks from Oregon and Washington and then state that Wyoming's framework is good because it is better than Oregon's or Washington's but, this type of argument is misplaced.

Neither Oregon's nor Washington's regulatory frameworks should be compared to Wyoming's at all. Both of these states are removing (and have removed) coal from their rates and their policies are antagonistic to Wyoming's interests. Indeed, this is why the Company is currently engaged in negotiations to develop a new cost allocation methodology which will resolve this inter-state tension. In the context of Wyoming rates, it is more accurate to ignore those states' regulatory frameworks altogether. In doing so, WIEC's argument becomes that Wyoming's 80/20 sharing arrangement falls to the bottom of the group, wherein that "group" is Idaho, Wyoming and Utah – and these are the comparable states.

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[176] Direct Testimony of Ramon J. Mitchell at 49 (RMP Exhibit 10.0).
[177] Direct Testimony of Kevin C. Higgins at 47 (WIEC Exhibit No. 200).

C. Reply to WOCA

Q. WOCA identifies four functions it believes need to be incentivized by the ECAM's sharing band after EDAM participation: "(1) fuel procurement; (2) resource selection; (3) generation maintenance; and (4) scheduling generation maintenance."[178] How do you respond?

A. Fuel procurement is hedging and generation maintenance is planned maintenance I have discussed above in the Reply to WIEC how these are either not under the purview of cost control or few in number and easily accessible for judicious prudency review. Regarding resource selection, Wyoming has an existing process for review of resource selection, which includes GRCs, and as mentioned in my initial filing, purchased power agreements are also few in number and easily accessible for judicious prudency review.[179] WOCA's arguments here advocate well for the use of judicious prudency review coupled with elimination of the sharing band.

Q. Like WIEC, WOCA misrepresents my testimony and states that the Company's deterioration in NPC forecast accuracy is related to the Company's investments in renewable generation.[180] How do you respond?

A. My response here is the same as my response to WIEC. "Had the Company not installed a single megawatt of wind or solar generation, the NPC forecast would still be driven by market prices and, therefore, still suffer from difficulties in forecast accuracy resulting from the region-wide adoption of these weather dependent resources."[181]

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[178] Direct Testimony of Colin T. Fitzhenry at 22 (WOCA Exhibit No. 603).
[179] Direct Testimony of Ramon J. Mitchell at 42 (RMP Exhibit 10.0).
[180] Direct Testimony of Colin T. Fitzhenry at 24 (WOCA Exhibit No. 603).
[181] Direct Testimony of Ramon J. Mitchell at 49 (RMP Exhibit 10.0).

Q. WOCA claims that without the sharing band, the Company's thought process would be "if we miss on the NPC forecast this time, we will simply recover our shortfall in the ECAM."[182] Is this true?

A. No. This is not the Company's thought process. As I have explained above, and in my initial filing, judicious prudency review will continue to incentivize the Company to control costs following elimination of the sharing band. Specifically, "[w]ith participation in an organized market, the quantity of transactions to review are less numerous because the majority of NPC transactions and decisions will be automated under the purview of an independent system operator. The remaining NPC transactions relevant for prudency reviews become smaller by magnitudes and therefore manageable instead of monumental."[183]

Q. Overall, WOCA's ECAM sharing band discussion boils down to one major point "[i]f the sharing band is not applicable to the ECAM, then [Rocky Mountain Power] will not be incented to control costs."[184] How do you respond?

A. I have already explained above that the ECAM sharing band does not incentivize the Company to control NPC. I propose instead judicious prudency review coupled with elimination of the sharing band.

D. Reply to Sierra Club

Q. Apart from the arguments advanced by WIEC and WOCA, what other arguments does the Sierra Club raise?

A. The Sierra Club presents a particularly interesting argument which appears to be that

[182] Direct Testimony of Colin T. Fitzhenry at 25 (WOCA Exhibit No. 603).
[183] Direct Testimony of Ramon J. Mitchell at 61 (RMP Exhibit 10.0).
[184] Direct Testimony of Colin T. Fitzhenry at 25 (WOCA Exhibit No. 603).

the ECAM sharing band penalizes coal and gas resources and therefore the sharing band is needed to encourage the Company to acquire more wind and solar resources.

The Sierra Club asserts that, if full cost-recovery is assured through the ECAM, there will be nothing to incentivize the utility to control resource acquisition in the long-term planning horizon and "utilities do not appropriately account for the risk of [coal or gas] fuel resource acquisition, especially not when compared to the much lower risk of low-cost solar and wind generation, which do not suffer from fluctuating costs."[185] Specifically, the Sierra Club's argument boils down to the fact that "[w]hile RMP cannot control market prices for gas, coal, or power produced by others, it can shape its NPC by a judicious resource expansion."[186] The Sierra Club's idea of a "judicious resource expansion" appears to be confined to "adding more wind and solar."[187]

As I mentioned above, Wyoming has an existing process for review of resource decisions, which includes GRCs, and purchased power agreements are few in number and easily accessible for prudency review. Regardless, the Sierra Club's testimony completely misses the mark with their resource technology-type biased focus on wind and solar resources. Because of this bias, I do not find their testimony persuasive in this Wyoming GRC.

Q. Do you have any further comments on the contents of the Sierra Club's testimony?

A. Yes. As a final matter, the Sierra Club produces Exhibit 302, which shows on page 2 a hypothetical impact of changes in average load to market prices and concludes that volatility in renewable resources have only a small impact on market prices.[188] The

[185] Direct Testimony of Ronald. J. Binz at 17 (Sierra Club Exhibit No. 300).
[186] *Id*., at 19.
[187] *Id*.
[188] Illustrative Resources Stack at 2 (Sierra Club Exhibit No. 302).

fatal flaw with this argument is that load serving entities (*e.g.*, the Company) are not particularly concerned with *average* load. They are concerned with *peak* load. Summer and winter peak periods are periods of high customer demand and stressed system conditions and higher power prices in those periods will produce NPC that are substantially higher than the relatively slight decreases in NPC resulting from low prices in spring and fall months, which have light load and relatively mild system conditions.

The Sierra Club's exhibit is particularly helpful to the Company's argument that the regional proliferation[189] of intermittent weather-dependent generation is diminishing the accuracy of regional power market price forecasts. Consider the two "Average Load" lines in Sierra Club's Exhibit 302, page 2. Shift those two lines to the right by about 2,000 MW and one will observe that the market price jumps from around $32/MWh to around $80/MWh with loss of renewable generation. That is to say, the market price moves up by about $48/MWh or 150 percent with loss of renewables; this is the problem with market prices in today's landscape. Renewable resources are intermittent generators and when energy is most needed to serve load during peak periods, substantial loss of wind or of sunshine swings power prices up substantially. I detailed this impact (which is asymmetrical) in my initial filing with a real example, instead of a hypothetical one,[190] and the Sierra Club mistakes the concerns of power system operators for average load instead of peak load.

Q. Does this conclude your rebuttal testimony?

A. Yes.

[189] Not the Company's generation, but the western interconnection's generation.
[190] Direct Testimony of Ramon J. Mitchell at 50-52 (RMP Exhibit 10.0).

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC SERVICE RATES BY APPROXIMATELY $140.2 MILLION PER YEAR OR 21.6 PERCENT AND TO REVISE THE ENERGY COST ADJUSTMENT MECHANISM	DOCKET NO. 20000-633-ER-23 (RECORD NO. 17252)

AFFIDAVIT, OATH AND VERIFICATION

Ramon Mitchell (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is the Manager, Net Power Costs for PacifiCorp, which is a party in this matter.

Affiant prepared and caused to be filed the foregoing testimony. Affiant has, by all necessary action, been duly authorized to file this testimony and make this Oath and Verification.

Affiant hereby verifies that, based on Affiant's knowledge, all statements and information contained within the testimony and all of its associated attachments are true and complete and constitute the recommendations of the Affiant in their official capacity as Manager, Net Power Costs.

Further Affiant Sayeth Not.

Dated this 23rd day of September, 2023

Ramon Mitchell
Manager, Net Power Costs

STATE OF Washington)
) SS:
COUNTY OF Clark)

The foregoing was acknowledged before me by Ramon Mitchell on this 23 day of September, 2023. Witness my hand and official seal.

Notary Public

My Commission Expires: April 1, 2027

NOTARY PUBLIC
STATE OF WASHINGTON
DION LABADIE
MY COMMISSION EXPIRES
APRIL 01, 2027
COMMISSION # 206461

Rocky Mountain Power
Exhibit 10.8
Docket No. 20000-633-ER-23
Witness: Ramon J. Mitchell

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Ramon J. Mitchell

Effects of Ambient Temperature on Gas Generation Output

September 2023

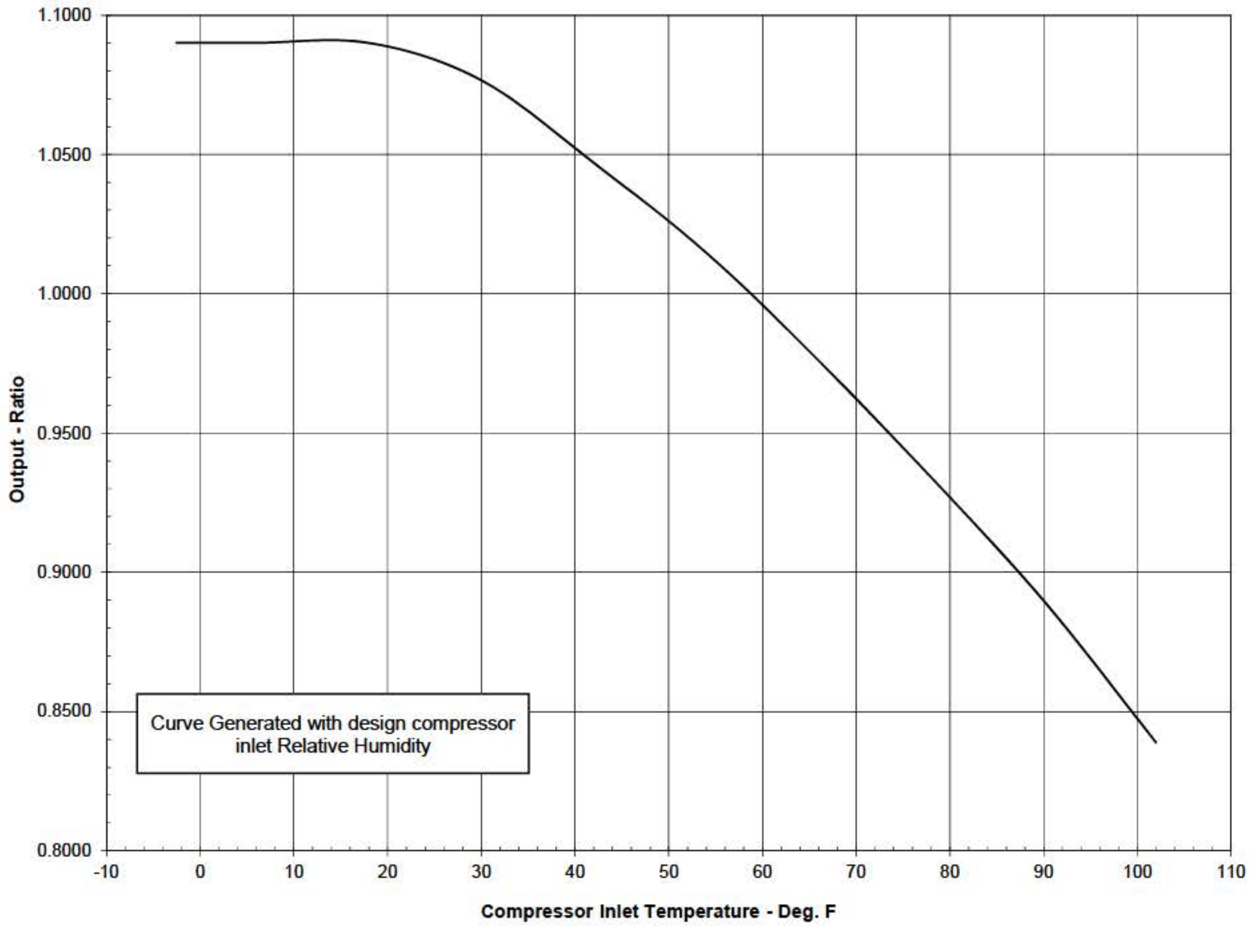
General Electric Model 7F.04 Gas Turbine

[redacted]

Estimated Performance

Effect of Compressor Inlet Temperature on Output

Design Values Referenced on 104H6508 Rev - Sheet 1
Fuel: Gas
Mode: Base
[redacted]



	Units										
Compressor Inlet Temperature	F	-2.55	6.00	18.00	30.00	42.00	54.00	66.00	78.00	90.00	102.00
Output Ratio		1.09008	1.09008	1.09008	1.07666	1.04701	1.01476	0.97597	0.93401	0.88979	0.83877

[redacted]

104H6508 Rev -
Sheet 3

Rocky Mountain Power
Exhibit 10.9
Docket No. 20000-633-ER-23
Witness: Ramon J. Mitchell

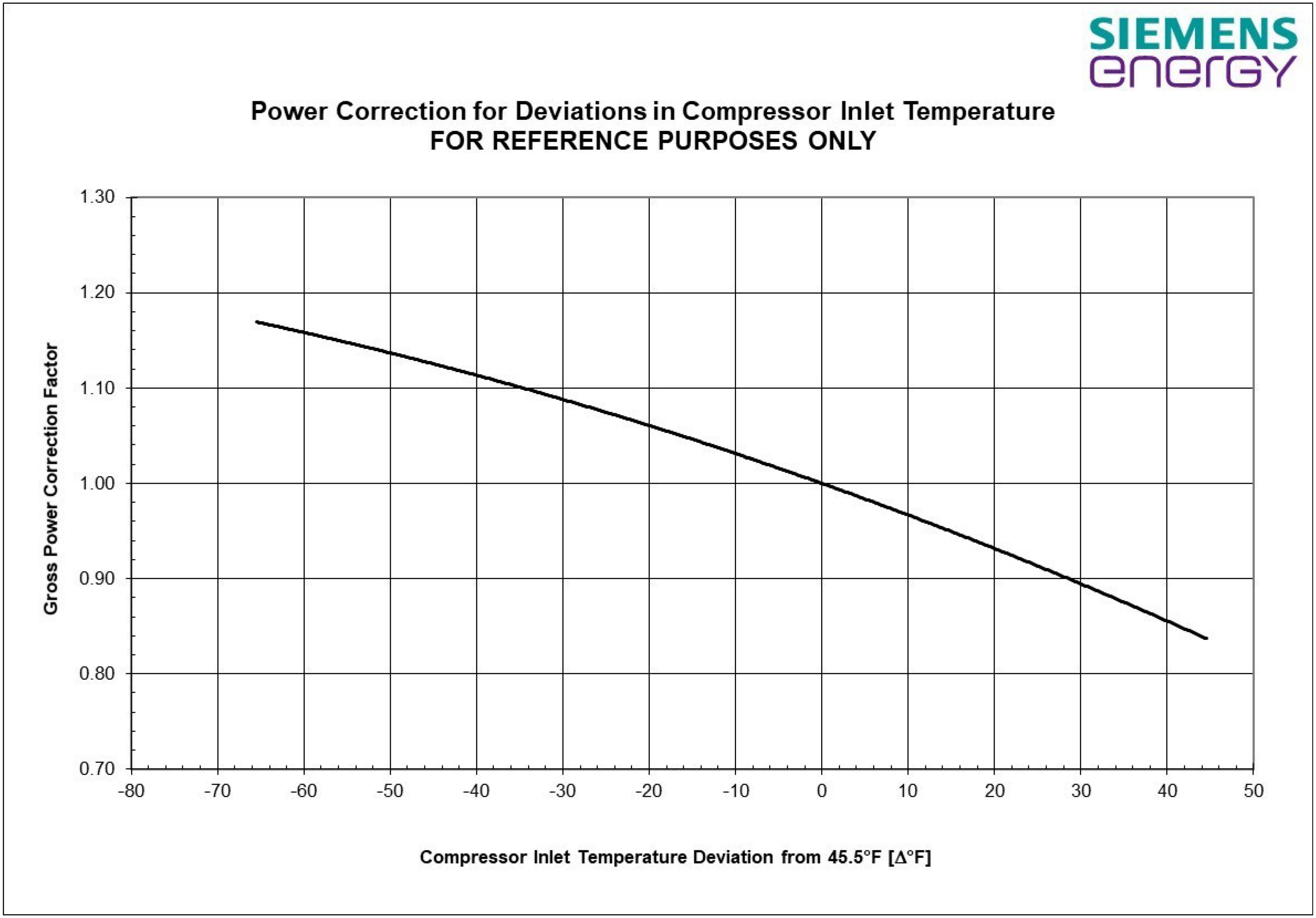
BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Ramon J. Mitchell

Effects of Ambient Temperature on Coal Generation Output

September 2023


SIEMENS energy
Power Correction for Deviations in Compressor Inlet Temperature
FOR REFERENCE PURPOSES ONLY
Gross Power Correction Factor
1.30
1.20
1.10
1.00
0.90
0.80
0.70
-80
-70
-60
-50
-40
-30
-20
-10
0
10
20
30
40
50
Compressor Inlet Temperature Deviation from 45.5°F [Δ°F]

Rocky Mountain Power
Exhibit 10.10
Docket No. 20000-633-ER-23
Witness: Ramon J. Mitchell

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Ramon J. Mitchell

Supplemental Direct Testimony Aurora Version

September 2023

RMP 5.1: Refer to WIEC Exhibit No. 202, Page 7, Table BGM-1: For those values in Table BGM-1 which were derived using Aurora, which Aurora version (or versions) did WIEC witness Bradley G. Mullins utilize?

RESPONSE: WIEC's witness Bradley Mullins used AURORA version 14.2.1052 in developing the referenced testimony and the values in the referenced table.

Respondent: Bradley G. Mullins

Witness: Bradley G. Mullins

20000-633-ER-23 / Rocky Mountain Power
August 1, 2023
WIEC Data Request 1.4 – 1st Supplemental

WIEC Data Request 1.4

Please provide WIEC consultant Bradley Mullins with an intervenor license necessary to access and use the AURORA model.

Bradley G. Mullins
MW Analytics Energy and Utility Consulting
Tietotie 2, Suite 208,
Oulunsalo, Finland FI 90460
E-mail: brmullins@mwanalytics.com
Telephone: [redacted]

1st Supplemental Response to WIEC Data Request 1.4

Further to the Company's response to WIEC Data Request 1.4 dated April 24, 2023, the Company provides the following supplemental information:

On July 31, 2023, the Company provided access (via BOX) to the Aurora net power costs (NPC) project supporting the supplemental direct testimony of Company witness, Ramon J. Mitchell in this GRC proceeding to Bradley Mullins, consultant representing the Wyoming Industrial Energy Consumers (WIEC). Please refer to the confidential work papers provided with and supporting Mr. Mitchell's supplemental direct testimony. The Aurora NPC project and its supporting work papers are confidential and are subject to the terms and conditions of the protective order in this GRC proceeding.

Note: the Aurora NPC project is "WY 20000-633-ER-23 GRC (2024) Mitchell-Update_Aurora v14.2.1059 CONF", and the version of the Aurora application used by PacifiCorp's NPC group for the supplemental direct testimony filing in this GRC proceeding is version 14.2.1059.

Confidential information is provided subject to Chapter 2, Section 30 of the Wyoming Public Service Commission's rules and Wyo. Stat. §16-4-203(a), (b), (d), or (g), and the protective order that was issued in this proceeding and will be made available to non-governmental parties who execute a confidentiality agreement.

Respondent: Ramon J. Mitchell

Witness: Ramon J. Mitchell