ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple
Salt Lake City, UT 84116

January 8, 2024

VIA ELECTRONIC FILING

Public Service Commission of Utah
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Administrator

Re: Docket No. 23-035-01
Rocky Mountain Power's Application for Approval of the 2023 Energy Balancing Account
Rocky Mountain Power's Rebuttal Testimony

In accordance with the Scheduling Order and Notice of Hearings issued by the Utah Public Service Commission ("Commission") on May 11, 2023, PacifiCorp, d.b.a. Rocky Mountain Power, hereby submits for electronic filing its rebuttal testimony in the above referenced matter.

The Company's filing includes the rebuttal testimony and two confidential exhibits of Mr. Jack Painter on behalf of the Company. Confidential information has been uploaded to the Commission's SFTP site and separately provided to intervening parties in this matter who have filed an Appendix A. Confidential information is provided subject to Public Service Commission of Utah Rule 746-1-602 and 746-1-603.

Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward
Senior Vice President, Regulation and Customer & Community Solutions

cc: Service List Docket No. 23-035-01

CERTIFICATE OF SERVICE

Docket No. 23-035-01

I hereby certify that on January 8, 2024, a true and correct copy of the foregoing was served by electronic mail to the following:

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Jack Painter

January 2024

Q. Please state your name, business address and present position with PacifiCorp, dba Rocky Mountain Power ("the Company or Rocky Mountain Power").

A. My name is Jack Painter and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Net Power Cost Specialist.

Q. Are you the same Jack Painter who submitted direct testimony and response testimony on behalf of the Company in this proceeding?

A. Yes.

PURPOSE OF TESTIMONY

Q. What is the purpose of your response testimony?

A. My testimony responds to the direct testimony of Ms. Alyson Anderson on behalf of the Office of Consumer Services ("OCS"), in support of the Division of Public Utilities' ("DPU") request to delay the prudence review of the Company's dispatch of coal resources during calendar year 2022. My testimony presents arguments against this proposal and explains that the Company has provided significant evidence of the prudence of our dispatch decisions while the OCS has offered no evidence that the Company did not appropriately and prudently dispatch its coal resources.

Q. Can you please summarize your testimony?

A. Yes. First, I address and explain why the OCS's request to delay review of EBA costs is unnecessary and inconsistent with the Public Service Commission of Utah ("Commission") guidance on this issue. Afterwards, my testimony responds to OCS's concerns on the economic dispatch of coal resources and explains the conclusions from the report that the Company recently filed in the Idaho Energy Cost Adjustment Mechanism ("ECAM"), which was requested by the OCS and the DPU.

Q. Do you present any exhibits with your rebuttal testimony?

A. Yes. My rebuttal testimony includes two confidential exhibits. Confidential Exhibit RMP___(JP-1R) provides a copy of a report prepared by the Company at the direction of the Idaho Public Utilities Commission ("IPUC") as part of the Idaho ECAM for calendar year 2022 ("Coal Report"). The IPUC directed the Company to prepare the Coal Report to investigate and report on the issues causing the extraordinarily high net power costs ("NPC") experienced in calendar year 2022, with a focus on the lack of coal generation and coal supplies, and the Company's management of those issues, as described by IPUC Staff in the Idaho ECAM. The Company submitted the Coal Report to the IPUC on December 22, 2023, in compliance with an IPUC Order issued May 31, 2023.[1] The Company also provided a copy of the Coal Report to the DPU, OCS, and Utah Association of Energy Users ("UAE") through discovery on the same day it was filed with the IPUC.[2] I provide this Coal Report for the Commission and the record in this matter as it is the basis of the DPU's recommendation in this case to retain the ability to propose adjustments to calendar year 2022 costs associated with the Company's dispatch of its coal generation fleet in the 2024 EBA. Also attached to my testimony is Confidential Exhibit RMP___(JP-2R) which are copies of certain discovery related to coal dispatch that was provided to the DPU during this case.

Q. In what capacity were you involved with the preparation of the Coal Report?

A. I was one of many subject matter experts within the Company who contributed to the preparation of the Coal Report along with other experts from energy supply management and the fuels groups.

[1] DPU Exhibit 1.7D Dir, Idaho PUC Case No. PAC-E-23-09, Order No. 35801.
[2] Confidential Exhibit RMP___(JP-2R), 1st Supplemental Response to DPU Data Request 17.4.

REQUEST FOR EXTENDED REVIEW OF CY 2022 COSTS IN THE 2024 EBA

Q. Please describe OCS's request for extended review of CY 2022 EBA costs in the 2024 EBA.

A. The OCS states that it shares the DPU's concerns regarding the magnitude of the EBA recovery in this proceeding as well as the prudence of the Company's dispatch of its coal resources. The OCS supports the DPU's request to be able to preserve its ability to make recommended adjustments to the deferred EBA costs for calendar year 2022 in this case during the course of the Company's next EBA filing.[3]

Q. Why should the Commission reject the request for additional time to review CY 2022 EBA costs?

A. As stated in my direct testimony, Utah Code Ann. § 54-7-13.5(2)(l)(ii) requires the Commission to issue a final order establishing and fixing an electrical corporation's balancing account "before the expiration of 300 days after the day on which the electrical corporation files a complete filing." In 2022 the Commission denied an application by the Company to implement a procedural schedule that did not comply with the 300-day statutory requirement.[4] Additionally, in the 2022 EBA order, the Commission stated it believed serious legal questions existed when it addressed a request from UAE to condition recovery for certain costs in that case beyond the final order, which would essentially have allowed parties to "revisit the issue in the future."[5]

[3] Exhibit OCS-1D, Testimony of Alyson Anderson at 6-7.
[4] *Rocky Mountain Power's Application for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No. 09-035-15, Order at 4 (Feb. 24, 2022).
[5] *Rocky Mountain Power's Application for Approval of the 2022 Energy Balancing Account*, Docket No. 22-035-01, Order at 28 (Jan. 9, 2023).

Q. Even if Utah law does not require a final order within 300 days, why should the Commission reject the OCS's arguments in support of delaying the review of costs in this EBA filing to the next EBA?

A. The Commission should reject the OCS's arguments in support of the DPU's proposal to delay review of the costs because the Company has provided significant evidence on the prudence of the Company's economic dispatch of its coal units and addressed the concerns presented by the parties in this proceeding with explanations and evidence. The Company has provided the information requested by parties in this case to describe the conditions in 2022. It is inappropriate for the DPU and OCS to expect two complete EBA cycles to review the Company's EBA application and determine prudency.

Q. What arguments does the OCS present to support its recommendation?

A. The OCS cites a prior Commission order dealing with prior period accounting adjustments to the EBA to argue that a delay in the review of the calendar year 2022 deferred costs is appropriate. The OCS also argues that the size of the request in this case supports additional review time, suggesting that the dispatch of coal resources contributed to the size of the EBA deferral. My testimony addresses these arguments and explains why they are not valid.

Q. Please describe the Commission's decision that OCS references related to the treatment of out-of-period adjustments in the EBA.

A. On February 16, 2017, the Commission issued an order in Docket No. 09-035-15 where it ruled that the Company could include certain prior period adjustments in the EBA ("Prior Period Order"). The OCS argues that the Prior Period Order constitutes precedence for the requested delay in prudence review sought by the DPU in this case.

Specifically, the OCS quotes Prior Period Order language that states that not allowing prior period adjustments would "disallow prudent NPC amounts booked in accordance with generally accepted accounting principles and cites examples where estimated or accrued costs or benefits from prior periods could not be reconciled with actual costs or benefits until after an audit or until more accurate information became available."[6]

Q. Can you please provide the context for the facts in that matter and contrast how the circumstances compare to the proposal in this case?

A. In that order, the Commission was ruling on the issue of accounting entries pertaining to operating periods prior to the deferral period. Specifically, the Company was arguing to be able to continue its policy of ensuring NPC accurately reflected the impact of entries booked according to Generally Accepted Accounting Principles ("GAAP") pertaining to operating periods prior to the implementation of the EBA. For example, in some instances the Company may have a dispute with a counterparty during the settlement of an energy sales transaction. In these circumstances, the Company books an estimate to properly account for the purchase or sale that has taken place, so its books are as accurate as possible until the dispute is resolved. Then, once the dispute is resolved, accounting entries may be required to properly reflect the outcome. If the dispute is resolved after the end of a given EBA deferral period, the true-up entry becomes a prior period, or out-of-period, adjustment. In that proceeding, the DPU argued that these out-of-period adjustments should not be included in the EBA. The Commission made a finding in its Prior Period Order that these types of accounting adjustments are permitted under Utah Code Ann. § 54-7-13.5. The Commission also

[6] Docket No. 09-035-15, Order at 13 (Feb. 16, 2017).

stated, "consistent with our experience with other balancing accounts, we find that difficulties exist with closing various transactions within the deferral period."

On the other hand, the DPU and OCS argue in this proceeding that they should be allowed to propose adjustments to costs from this EBA proceedings in a future EBA proceeding. Allowing prior period accounting adjustments in order to accurately reflect net power costs is not the same as allowing parties to take longer than the 190 days provided in the procedural schedule in the EBA tariff[7], and longer than the 300 days required under Utah Code Ann. § 54-7-13.5(2)(l)(ii) to review the Company's case and propose adjustments regarding the prudence of the costs that are included. These are distinctly different issues, and the Prior Period Order does not establish precedent that the DPU's proposal is "appropriate and allowed within the EBA review process"[8] as asserted by Ms. Anderson.

Q. Even if the Prior Period Order could be construed as precedent to approve the DPU's request, are there other facts the Commission should consider?

A. I am aware that at the time the Prior Period Order was issued, the EBA did not have the 300-day statutory period. The Utah Legislature enacted the required 300-day statutory review period in the EBA proceedings in the 2021 Legislative Session, after this order was issued.

[7] Electric Service Schedule No. 94, Sheet 94.3.
[8] Exhibit OCS-1D, Anderson at 3.

Q. In its arguments leading up to the Prior Period Order, the Company stated that Utah Code Ann. § 54-7-13.5(2)(c)(ii) allows for reconciliation of EBA accounts and does not preclude updates when new information becomes available. Does the DPU's and OCS's request fall under the umbrella of "new information"?

A. No. The DPU and OCS argues that the prudency review of the calendar year 2022 costs associated with the Company's coal dispatch should be allowed in the 2024 EBA because the Coal Report is new information. Although the IPUC directed the Company to prepare the Coal Report on May 31, 2023, it did not require it to be filed until the end of 2023. The DPU and OCS argue that waiting for the Coal Report was necessary before the prudence review could be conducted in this case. While the Coal Report was not available until December 22, 2023, the information presented is not new information and was available to the DPU and OCS at any time during this proceeding. Nothing prevented any party in this case from conducting its own review, and the information necessary to conduct a review could have been requested and audited by the DPU, OCS, and any other intervenor in this proceeding during the pendency of the docket.

Q. The OCS claims that the DPU "attempted to investigate the reason the coal units did not economically dispatch as expected during the second half of 2022[,]"[9] specifically referencing data request DPU 17.4. How do you respond?

A. Although the IPUC issued its order directing the Company to prepare the Coal Report on May 31, 2023, the DPU did not submit data request set 17, including question 4 inquiring about the report, until October 13, 2023. At the DPU's request, the Company

[9] Exhibit OCS-1D, Anderson at 5.

expedited its turnaround time to respond, and provided responses to DPU's set 17 on October 26, 2023 (8 days early). The questions are provided in Confidential Exhibit RMP___(JP-2R). Although the OCS characterizes this as the DPU's attempt to investigate the dispatch of coal resources, the questions were asked less than a month before the DPU's audit report was due.

Q. What evidence does the DPU and OCS cite that led them to question whether the Company's dispatch of its coal resources was prudent, warranting additional investigation?

A. Ms. Anderson's testimony includes Figure 1, comparing actual and base NPC, noting that the actual costs increased significantly compared to the projection in the second half of 2022. Ms. Anderson concludes that this disparity warrants additional investigation as proposed by the DPU.

Q. What is the source of this information and when was it provided?

A. As referenced in footnote 6 of Ms. Anderson's testimony, this information was obtained from my Direct Testimony that was filed May 1, 2023.

Q. Did IPUC Staff specify what information it wanted from the Company to review CY 2022 coal dispatch?

A. Yes. IPUC Staff provided a list of requested information in its comments.[10]

Q. When did IPUC Staff file its comments containing this list of requested information?

A. The IPUC Staff comments were submitted in the Idaho ECAM proceeding on May 10, 2023.

[10] DPU Exhibit 1.7B Dir, Idaho PUC Case No. PAC-E-23-09, Comments of the Commission Staff at 7-8.

Q. Do you believe the DPU was aware of this list of information requested by IPUC Staff to conduct a comprehensive review of the Company's coal dispatch?

A. Yes. The DPU attached a copy of the IPUC Staff comments submitted by the DPU as DPU Exhibit 1.7B Dir.

Q. Could similar information have been requested by the DPU, OCS, or other intervenors earlier in this proceeding?

A. Yes. The Company had the information and even told the IPUC in reply comments that it was able to provide the information within a month.[11] The DPU and OCS point to information that was provided in the Company's May 1, 2023 filing as the evidence suggesting additional review was warranted. Nothing precluded the DPU, OCS, or any other party from acting on its concerns earlier in this proceeding and requesting whatever information deemed necessary to conduct a prudency review at any time between May 1, 2023 and November 7, 2023. The DPU and OCS claim the Coal Report is new information and was not available in time to inform potential adjustments in this case, but it is unclear to the Company why the DPU did not investigate on their own accord since they claim they found evidence in the May 1, 2023 filing that suggested an investigation was needed.

Q. What information was provided regarding the coal dispatch issue that the parties possessed? When was the timing of that information made available?

A. As I noted in my previous testimony, the Company has been transparent and forthright regarding the coal inventory challenges that were faced in 2022, and this was noted by

[11] DPU Exhibit 1.7C Dir, Idaho PUC Case No. PAC-E-23-09, RMP Reply Comments 5-17-2023 (CONFIDENTIAL) at 15- 16.

the DPU in their coal inventory report in March of this year.[12] In addition to the annual fuel audit, the Company also provided information in this proceeding through the filing requirements as well as discovery. To illustrate, I have provided the discovery in this proceeding pertaining to calendar year 2022 coal dispatch in Confidential Exhibit RMP___(JP-2R).[13]

Q. Was any information included in the Coal Report unavailable at the beginning of this proceeding?

A. No, and as I noted above, the Company has been forthright and transparent about the recent issues in maintaining coal inventory in Utah.

Q. Has the Company provided full and thorough information regarding power costs since the beginning of this filing?

A. Yes. The Company made a complete filing on May 1, 2023, with evidence and explanations for its net power costs including the filing requirements and additional filing requirements. As parties reviewed the Company's filing and submitted discovery to review aspects of the filing, the Company provided complete and accurate responses to discovery, including the questions asked about coal dispatch. Until the discovery received from the DPU in October, the Company was not aware of the extent of DPU's concerns with its coal dispatch. The Company was certainly not aware of the DPU's stance that its review of calendar year 2022 costs was waiting on information from a proceeding in a different jurisdiction until its November 7, 2023, Audit Report.

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[12] *Division of Public Utilities' Audit of PacifiCorp's 2022 Fuel Inventory Policies and Practices*, Docket No. 23-035-14 Memorandum at 6-7 (Mar. 29, 2022).
[13] The Company notes that DPU data request set 14 also discussed coal dispatch, but the DPU specified that the questions pertained to the values for actual NPC for January – June 2023 as reported in the 2nd Quarter 2023 Energy Balancing Account report filed in this proceeding on August 31, 2023.

Q. If the information was available earlier, why was the IPUC Coal Report not prepared until December 22, 2023?

A. Although the Company offered to provide the information to resolve IPUC Staff's concerns with a one-month process from its May 17, 2023, reply comments,[14] the IPUC determined the timing of the Coal Report would be the end of 2023.

Q. Ms. Anderson states that the OCS agrees with the DPU that the size of the EBA deferral in this case warrants additional time to review and audit the EBA. Do you agree?

A. No. The size of the EBA deferral in any given year is simply calculated as the difference between Base NPC and Actual NPC. EBA filings are a review of the Company's entire NPC, not just the incremental portion of NPC that has been deferred. The Company does not disagree that calendar year 2022 NPC was relatively large in magnitude and that the DPU's responsibility to audit its NPC is a significant undertaking. However, consideration for the magnitude and importance of NPC review is already built into the EBA proceedings through a relatively lengthy 300-day statutory timeframe, of which 190 days is provided to the DPU to conduct its Audit. In comparison, the statutory period for a general rate case, where *all* the Company's costs and revenues are reviewed is only 240 days. All EBA filings, regardless of size, should be able to be reviewed within the 300-day statutory limit and the arbitrary size of a deferral in any given year is not justification to lengthen the time for review by an entire EBA cycle.

[14] DPU Exhibit 1.7C Dir, Idaho PUC Case No. PAC-E-23-09, RMP Reply Comments 5-17-2023 (CONFIDENTIAL) at 15- 16.

ECONOMIC DISPATCH OF COAL RESOURCES

Q. Setting aside the previous discussion regarding the DPU and OCS request for additional time to review the Company's coal dispatch, were the Company's actions with respect to dispatch of its coal resources in CY 2022 prudent and reasonable?

A. Yes. Actual coal generation in calendar year 2022 was reasonable and in the best interest of its customers. The Company operated prudently based on market conditions that were influenced by multiple factors including but not limited to, the war in the Ukraine, high market power prices and gas prices, and extreme weather events. The Company was also challenged by force majeure events outside of its control, but the Company was properly prepared for these events with sufficient stockpile supplies at both the Hunter and Huntington plants as well as the Rock Garden safety pile. Faced with force majeure events, the Company took proactive measures to deploy its coal fleet prudently by working to secure additional coal while prudently managing its coal supply to ensure its coal fleet reliability was maintained.[15]

Q. Were the conclusions in the Coal Report consistent with your testimony filed on December 7, 2023?

A. Yes. The information provided and explanations are consistent with my response testimony, which addressed the same issues impacting the company's NPC.[16] I would however note that Base NPC rates used in the Idaho ECAM are different than the Base NPC rates used in the EBA. This means that some of the quantitative analysis in the Idaho ECAM Report would be different for Utah. However, the discussion of the

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[15] Confidential Exhibit RMP___(JP-1R) at 23-24.
[16] Response Testimony of Jack Painter at 2-7 (Dec. 7, 2023).

conditions and the actions taken by the Company to prudently respond to multiple unforeseen and uncontrollable events is valid for Utah, and consistent with all the previous testimony provided in this docket.

Q. OCS witness Anderson additionally refers to DPU witness Gary Smith's testimony regarding the economic dispatch of the Company's coal resources.[17] Has the Company addressed those concerns?

A. Yes, as I described earlier, I addressed these concerns in my response testimony.[18]

Q. Has the Company provided sufficient evidence to explain the Company's coal dispatch in this proceeding?

A. Yes. Despite the OCS concerns regarding the economics of the Company's coal dispatch, my response testimony provided sufficient evidence to describe difficulties in maintaining coal stockpiles for the Company's Utah coal plants in 2022, and the associated impact on coal generation that occurred.

Q. The OCS notes that the size of the deferral balance has increased, and that this is the largest ever deferral balance and there are significant differences between actuals and the forecast.[19] Has the Company provided an explanation of the cost drivers causing this increased balance?

A. Yes. The Company's baseline NPC forecast was set in 2020 (for a 2021 test year) and natural gas and power market conditions have changed significantly since. My direct testimony provided an overview of the drivers causing these variances.[20] Comparing actual conditions from 2022 to a normalized forecast set in 2020 does not provide any

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[17] Exhibit OCS-1D, Anderson at 4-5.
[18] Response Testimony of Jack Painter at 2-7.
[19] Exhibit OCS-1D, Anderson at 3-4.
[20] Direct Testimony of Jack Painter at 15-19 (May 1, 2023).

indication or evidence regarding the prudence of the actual costs that were incurred in 2022. There will be differences, and with the change in natural gas markets, power markets, and significant weather events that has occurred since 2020, the changes in actual operations when compared to a forecast are dramatic.

CONCLUSION

Q. What is your recommendation to the Commission?

A. The Company requests the Commission reject the OCS recommendation that the Commission allow parties to propose adjustments to calendar year 2022 costs in the 2024 EBA and approve the Company's request to recover $175,029,815 as presented in its initial application.

Q. Does this conclude your rebuttal testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Exhibit RMP___(JP-1R)
Docket No. 23-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Rebuttal Testimony of Jack Painter

ID ECAM Investigation Report

January 2024

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple, Suite 330
Salt Lake City, UT 84116

December 22, 2023

VIA ELECTRONIC DELIVERY

Commission Secretary
Idaho Public Utilities Commission
11331 W. Chinden Blvd
Building 8 Suite 201A
Boise, ID 83714

**RE: 2022 ECAM INVESTIGATIVE REPORT IN CASE NO. PAC-E-23-09
IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER REQUESTING APPROVAL OF $32.5 MILLON ECAM DEFERRAL**

Attention: Commission Secretary

Pursuant to Order No. 35801 in the above referenced matter Rocky Mountain Power hereby respectfully submits its 2022 Energy Cost Adjustment Mechanism (ECAM) Confidential Investigative Report to the Idaho Public Utilities Commission. Included with this filing is the attorney's certificate claim of confidentiality relating to the 2022 ECAM Investigative Report, two confidential exhibits, and confidential workpapers.

Informal inquiries may be directed to Mark Alder, Idaho Regulatory Manager at (801) 220-2313.

Very truly yours,

Joelle Steward
Senior Vice President, Regulation and Customer & Community Solutions

Enclosures

CC: Terri Carlock
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Attorney for Rocky Mountain Power

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER REQUESTING APPROVAL OF $32.5 MILLON ECAM DEFERRAL	)	CASE NO. PAC-E-23-09 ATTORNEY'S CERTIFICATE CLAIM OF CONFIDENTIALITY RELATING TO THE 2022 ECAM INVESTIGATIVE REPORT

I, Joe Dallas, represent Rocky Mountain Power in the above captioned matter. I am an attorney for Rocky Mountain Power.

I make this certification and claim of confidentiality regarding the response to the attached Idaho Public Utilities Commission Staff discovery request pursuant to IDAPA 31.01.01 because Rocky Mountain Power, through its response, is disclosing certain information that is Confidential and/or constitutes Trade Secrets as defined by Idaho Code Section 74-101, et seq. and 48-801 and protected under IDAPA 31.01.01.067 and 31.01.01.233. Specifically, the contracted coal amounts contain Company proprietary information that could be used to its commercial disadvantage.

Rocky Mountain Power herein asserts that the aforementioned responses contain confidential in that the information contains Company proprietary information.

I am of the opinion that this information is “Confidential,” as defined by Idaho Code Section 74-101, et seq. and 48-801, and should therefore be protected from public inspection, examination and copying, and should be utilized only in accordance with the terms of the Protective Agreement in this proceeding.

DATED this 22nd day of December, 2023.

Respectfully submitted,

By______________________________
Joe Dallas
Senior Attorney
Rocky Mountain Power

Rocky Mountain Power | Pacific Power

ROCKY MOUNTAIN POWER'S 2022 ENERGY COST ADJUSTMENT MECHANISM CONFIDENTIAL INVESTIGATIVE REPORT

Case No. PAC-E-23-09 / 2022 ECAM / IPUC Order No. 35801

December 2023

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List of Exhibits

1.0 Executive Summary

As directed by the Idaho Public Utilities Commission (the "Commission"), Rocky Mountain Power, a division of PacifiCorp (the "Company") hereby submits its 2022 Energy Cost Adjustment Mechanism ("ECAM") investigative report ("Investigative Report") in accordance with Order No. 35801 in Case No. PAC-E-23-09 ("2022 ECAM"). The Investigative Report focuses on the issues related to lower coal generation and coal supplies, the deployment of the Company's coal fleet during calendar year 2022, the impacts on net power costs ("NPC") and the Company's management of these issues during calendar year 2022. The difference between actual coal generation in the 2022 ECAM and the coal generation in the forecast base period included in the 2021 general rate case ("2021 GRC")[1] was five percent. This variance was reasonable given the inherent difficulty of forecasting variables that are dependent on weather and market conditions. This was particularly true in calendar year 2022 where the war in Ukraine and extreme weather events created unprecedented market conditions.

This Investigative Report begins with a background of the 2022 ECAM followed by a summary of the 2022 ECAM components and the coal generation and deployment circumstances of calendar year 2022 including the war in Ukraine, extreme weather and force majeure events from the Company's coal suppliers. Also provided is a summary of the Company's optimization models followed by a focus on the Company's coal acquisition process, coal market conditions in calendar year 2022 and the Company's coal supply agreements ("CSA") relevant to the 2022 ECAM.

2.0 Background

On March 30, 2023, the Company, under Case No. PAC-E-23-09, applied for Commission authorization to adjust its rates under the 2022 ECAM and requested approval of approximately $32.5 million in deferred costs for the period of January 1, 2022 through December 31, 2022, with a 2.3 percent overall increase to Electric Service No. 94, Energy Cost Adjustment ("Schedule 94").[2]

Prior to the Company's March 30, 2023, application, Commission Staff ("Staff") conducted a review and audit of the 2022 ECAM involving 26 production requests, an on-site visit to the Company facilities in Salt Lake City, Utah to meet with representatives from the fuel resources department, and an on-site visit to Portland, Oregon to meet with representatives from the Company's NPC department. Based on their findings and review of the Company's application,

[1] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Rates and Charges in Idaho and Approval of Proposed Electric Service Schedules and Regulations,* Case No. PAC-E-21-07.
[2] *In the Matter of the Application of Rocky Mountain Power Requesting Approval of $32.5 Million ECAM Deferral*, Case No. PAC-E-23-09, Application at 7 (March 30, 2023).

Staff submitted its comments on May 10, 2023, which recommended the Commission approve the Company's 2022 ECAM deferral balance along with the proposed Schedule 94 rate.

In addition, Staff recommended the Commission defer its decision on the prudence of the Company's 2022 NPC until an investigation was completed into the Company's ability to economically dispatch its coal plants in calendar year 2022. Staff requested the report to include details of the Company's forecasted load and its plan to meet this load requirement, a timeline of events leading to coal shortages and the inability to dispatch its coal plants, a list of issues that resulted in a significant increase in NPC, documentation of the Company's awareness of the shortfalls, alternative solutions considered, and the Company's proposed actions for the future to address these challenges effectively.

P4 Production, L.L.C. ("P4"), an affiliate of Bayer Corporation, also submitted comments noting concerns similar to Staff about the Company's coal generation levels in calendar year 2022. P4 requested a detailed discussion on the costs of short-term purchases in relation to the coal expense. In addition, P4 requested an explanation of the Company's ability to generate electricity from its coal units considering factors such as forced outages, scheduled maintenance, and operating constraints. The Company, through its discovery responses to both P4 and Staff, addressed in detail the forced and maintenance outages with a duration of longer than 72 hours and derates at 50 percent or more of net capacity.

On May 17, 2023, the Company submitted reply comments showing how it dispatched its coal generation units in calendar year 2022 in accordance with prudent utility practice, ensuring the maintenance of an adequate coal stockpile and consistent with least-cost economic dispatch principles. The Company's reply comments explained its coal acquisition process, its coal inventory levels at the Jim Bridger, Hunter and Huntington plants in calendar year 2022, and the process the Company followed to economically dispatch its coal generation units. The Company demonstrated that coal generation units were dispatched economically on a system-wide least-cost basis.

On May 31, 2023, the Commission issued Order No. 35801 approving the Company's $32.5 million in deferred costs for the deferral period January 1, 2022 through December 31, 2022, and approving a 2.3 percent increase to Schedule 94 with new rates effective June 1, 2023. The prudency determination of NPC in the 2022 ECAM was withheld until the Company submitted this Investigative Report before the end of the 2023 ECAM year.[3] In particular, the Commission directed the Company to submit a report focusing on any issues related to coal generation and supplies, and the Company's management of those issues, that occurred in calendar year 2022.[4]

[3] *In the Matter of the Application of Rocky Mountain Power Requesting Approval of $32.5 Million ECAM Deferral*, Case No. PAC-E-23-09, Order No. 35801 (May 31, 2023).
[4] *Id.* at 9.

3.0 2022 ECAM Summary

The Company's 2022 ECAM Application was for the recovery of $32.5 million as shown in Table 3.1 below:

Table 3.1 – 2022 ECAM Deferral

Calendar Year 2022 ECAM Deferral		
NPC Differential	$	35,322,826
EITF 04-6 Adjustment		190,656
LCAR		(1,578,588)
Total Deferral Before Sharing	$	33,934,894
Sharing Band		90%
Customer Reponsibility	$	30,541,405
Production Tax Credits	$	1,388,020
REP QF Adjustment		634,305
Wind Liquidated Damages		(295,039)
REC Deferral		(130,679)
Interest on Deferral		326,544
Annual Deferral (Jan - Dec 2022)	$	32,464,556

The recovery amount largely stemmed from the $35.3 million difference between the actual NPC ("Actual NPC") and the NPC collected from Idaho customers ("Base NPC") through rates set in the 2021 GRC. Three main drivers were responsible for the differential between Base NPC and Actual NPC; (1) worldwide natural gas supply and demand pressure that significantly impacted and increased power prices, as further explained in detail below; (2) extreme weather events that caused temporary increases in power and natural gas market prices; and (3) coal supply constraints due to force majeure claims. Despite facing numerous hurdles in calendar year 2022, further elaborated below, the Company experienced only a five percent discrepancy between the projected and actual coal generation. This variance is within the anticipated range as detailed in Section 4.0 of this Investigative Report.

3.1 War in Ukraine

During calendar year 2022, the conflict between Russia and the Ukraine resulted in decreased availability of natural gas in Europe, which was previously sourced from Russian imports. With decreased European supply, a measure of European demand turned to United States domestic supply to fill the gap. This resulted in increased competition over domestic supply, which drove regional natural gas fuel prices upwards due to domestic production being unable to keep pace with the increased demand. This increase in natural gas fuel prices correspondingly increased regional natural gas market prices and regional power market prices. The average cost of natural gas generation during the 2022 ECAM deferral period increased 66 percent from $26.95 per megawatt-hour ("MWh") in Base NPC to $44.61/MWh in Actual NPC as shown in Confidential Table 3.2 below:

Confidential Table 3.2 – Natural Gas Generation Costs – Forecast Base to Actual 2022

Plant	Base $/MWh	Actual $/MWh	Variance	Percent
Chehalis	[redacted]			
Currant Creek				
Gadsby				
Hermiston				
Lake Side 1				
Lake Side 2				
Naughton - Gas				
Total Gas	**$ 26.95**	**$ 44.61**	**$ 17.66**	**66%**

Because the Company operates its system on a least-cost economic dispatch model, even with higher natural gas prices throughout calendar year 2022, the Company's owned gas-generating plants were still, on average, significantly more economical than market power purchases during calendar year 2022, as shown in Confidential Table 3.3 below:

Confidential Table 3.3 – Power Pricing – Forecast Base to Actual 2022

Type	Base $/MWh	Actual $/MWh	Variance	Percent
Long-term Firm	[redacted]			
Qualifying Facilities				
Short-term/Balancing				
Total Purchases	**$ 46.19**	**$ 66.13**	**$ 19.93**	**43%**

During calendar year 2022, coal generation costs increased only moderately in comparison to natural gas and power pricing with a slight increase of two percent as shown in Confidential Table 3.4 below:

Confidential Table 3.4 – Coal Generation Costs – Forecast Base to Actual 2022

Plant	Base $/MWh	Actual $/MWh	Variance	Percent
Colstrip	[redacted]			
Craig				
Dave Johnston				
Hayden				
Hunter				
Huntington				
Jim Bridger				
Naughton				
Wyodak				
Total Coal	**$ 20.08**	**$ 20.47**	**$ 0.39**	**2%**

Actual 2022 coal generation costs, on a $/MWh basis, was within 2 percent of the forecasted cost of coal. As shown in Sections 6.0, 7.0, and 8.0 of this Investigative Report, the Company acted prudently by securing coal in advance of 2022 and utilized its coal fleet as prudently as possible during 2022 while ensuring reliability, despite force majeure events from coal suppliers in Utah.

3.2 Weather Events

In addition to the war in the Ukraine creating unique market conditions, several extreme and unforeseeable weather events occurred during the 2022 ECAM deferral period, all with a collective impact on Actual NPC throughout the year. Multiple heat waves across the Company's service territories throughout July 2022, August 2022 and September 2022 had a significant effect on market power prices leading to an increase in Actual NPC.[5] The NPC differential for those months alone amounted to $16.5 million and is almost half of the entire $35.3 million NPC variance in the 2022 ECAM.

In their comments filed on May 10, 2023, P4 suggests that during the extreme weather events "one would expect an increase in coal generation from historic levels since customer demand would be higher during such events." As P4 notes, the Company often experiences a corresponding increase in demand and load on its system during extreme weather events. To illustrate, actual Company system load in 2022 was 3,735,471 MWh, or 6 percent, above forecasted load. 42% of that increase (1,584,546 MWh), occurred in July, August, and September, when there were multiple heat waves across the Company's service area. However, because PacifiCorp's customer load demand peaks during the summer months of July, August, and September the Company's own coal and gas generating plants were already operating near peak capacity during much of the summer, which required the Company to purchase additional power to meet customers' needs during the extreme weather events in the Company's service territory.

Ongoing drought in the Western United States, dating back to the summer of 2020, has continued to impact Actual NPC through reduced availability of the Company's hydro resources. In calendar year 2022, actual generation from hydro resources was 1,505,231 MWh or 34 percent lower than forecasted base generation as shown in Table 3.5 below:

[5] PacifiCorp operates on a least-cost basis and does not rely on a weather-normalized forecast such as the one prepared to set Base NPC in the 2021 GRC. Each hour, day, or season presents unique conditions that differ from a weather-normalized forecast. These differences arise due to changes in market conditions, including market prices, load demand, hydroelectric generation, wind generation and solar generation. Consequently, the variance between forecast and actual conditions largely accounts for the difference between Base NPC and Actual NPC. In the 2021 GRC, the calendar year 2021 load forecast was an input to determine the Base NPC. This load forecast was a weather-normalized projection created in the spring of 2020 but was only one of many load forecasts across time that the Company has used to forecast the overall system generation as well as coal plant generation in order to acquire fuel in a manner that benefits customers.

Table 3.5 – Hydro Generation – Forecast Base to Actual 2022

Plant	Base MWh	Actual MWh	Variance	Percent
West Hydro	4,137,648	2,745,774	(1,391,874)	(34%)
East Hydro	303,342	189,984	(113,358)	(37%)
Total Hydro	**4,440,989**	**2,935,758**	**(1,505,231)**	**(34%)**

The estimated impact to the NPC differential in the 2022 ECAM due to drought is $8.9 million. A historic winter cyclone event in December 2022 occurred across the majority of the United States, impacting both market power prices and natural gas prices, along with an increase in demand. Natural gas prices across the Company's delivery points drastically increased. At the Opal natural gas trading hub, average market prices were 424 percent higher in December 2022 as compared to December 2021, while market prices at the Mid-Columbia and Four Corners trading hubs were, on average, 406 percent higher across all load hours. The NPC differential in December alone is $6.7 million, or 19 percent, of the NPC variance in the 2022 ECAM.

Overall, total-company coal fuel expense decreased by $18.8 million in the 2022 ECAM as shown in Confidential Table 3.6 primarily because coal generation volume decreased:

Confidential Table 3.6 – Coal Expense – Forecast Base to Actual 2022

Plant	Base Dollars	Actual Dollars	Variance	Percent
Colstrip	[redacted]			
Craig				
Dave Johnston				
Hayden				
Hunter				
Huntington				
Jim Bridger				
Naughton				
Wyodak				
Total Coal	**$ 599,876,421**	**$ 581,031,513**	**$ (18,844,907)**	**(3%)**

3.3 Force Majeure Events

Toward the end of 2022, due to conditions outside of the Company's control, coal supply issues causing delivery shortages began to impact the dispatch at Utah's Hunter and Huntington coal-generating plants. The operating mines in Utah's Book Cliffs and Wasatch Plateau coal fields experienced production difficulties due to a variety of geological, logistical, and financial challenges. Additionally, there was a mine fire at American Consolidated Natural Resources' Lila Canyon mine in September 2022. In recent years, the Lila Canyon mine has accounted for more than 25 percent of Utah's coal production. Several of the Company's coal suppliers issued force majeure notices in 2022 per the contract terms, which limited deliveries. Because of the coal supply constraints identified above, the Company had to take action to maintain the minimum stockpile reliability target.

Once informed of the force majeure claims, the Company proactively took actions to address coal supply constraints for its Utah plants during calendar year 2022, as further explained in Section 8.1 of this Investigative Report. Furthermore, based upon industry standard practice regarding the dispatch of fuel-limited resources, such as hydro plants, the Company calculated the dispatch price for the fuel-limited Hunter and Huntington units to maintain minimum coal stockpile reliability targets and secure availability for the benefit of customers during critical periods. The dispatch price for each of these units was calculated, to ensure an adequate coal stockpile, at $50-$70/MWh at Hunter in September 2022 and later in November 2022 at Huntington. By the end of 2022, the price was recalculated to approximately $90/MWh. The higher dispatch prices reflected the true cost of dispatching these resources with limited fuel supply and ensured that the Company's optimization models did not reduce coal stockpiles at Hunter and Huntington to unacceptable levels. It is important to note that despite the Hunter and Huntington dispatch prices being raised, Hunter and Huntington were not idled; they continued to operate to serve customers.

The Company's decision to calculate the dispatch price based on the economics of fuel-limited resources reflects its commitment to upholding reliability standards, and ensuring the availability of coal units when they are most needed. Although this calculation rendered the Hunter and Huntington plants less economically favorable to dispatch within the Company's operational optimization models in late 2022, it was necessary to maintain a prudent coal stockpile level in the aftermath of the unprecedented force majeure claims made by two coal suppliers, and to ensure reliability during high-demand periods.

4.0 Forecast Base Versus Actual Generation

As shown in Table 4.1 below, actual coal generation in the 2022 ECAM decreased by 1,484,137 MWh on a total-company basis, or five percent compared to the forecast base period (from the 2021 GRC). This five percent variance between forecast and actual is well within the expected range given that the periods compared are one year apart and the difficulty in forecasting with increasing variable renewable resources on the Company's system.

Table 4.1 – Coal Generation – Forecast Base to Actual 2022

Plant	Base MWh	Actual MWh	Variance	Percent
Colstrip	965,999	1,080,477	114,478	12%
Craig	997,267	1,066,740	69,473	7%
Dave Johnston	4,974,304	3,581,919	(1,392,385)	(28%)
Hayden	442,366	523,072	80,706	18%
Hunter	6,057,136	5,865,760	(191,376)	(3%)
Huntington	4,598,934	5,673,115	1,074,181	23%
Jim Bridger	7,656,465	7,376,117	(280,348)	(4%)
Naughton	2,511,449	1,879,970	(631,479)	(25%)
Wyodak	1,671,199	1,343,811	(327,388)	(20%)
Total Coal	**29,875,118**	**28,390,981**	**(1,484,137)**	**(5%)**

The largest decrease of 1,392,385 MWh at Dave Johnston plant (28 percent) is primarily due to the planned outage for the Dave Johnston Unit 4 boiler overhaul. Dave Johnston Unit 4 is the largest unit at the Dave Johnston plant with a capacity of 330 megawatts ("MW") versus 220 MW at Dave Johnston Unit 3, 106 MW at Dave Johnston Unit 2 and 99 MW at Dave Johnston Unit 1. The generation in Base NPC is modeled using a four-year overhaul average. Typically, each of the four units at the Dave Johnston plant undergoes a major overhaul every four years. Therefore, in years when the largest unit – Dave Johnston Unit 4 – is overhauled, such as in calendar year 2022, generation would be lower than the modeled average. Dave Johnston Unit 4 also experienced a number of forced outages during 2022 due to a variety of boiler tube leaks. Naughton plant generation was down 631,479 MWh or 25 percent, compared to the base forecast. Naughton Unit 2 experienced an unusually long outage period primarily due to generator and exciter problems. A 2022 Thermal Outage Summary is attached to this Investigative Report as Confidential Exhibit No. 1. Huntington generated 23 percent more than the base forecast or 1,074,181 MWh, despite the coal supply issues facing the Utah plants during the fourth quarter of 2022.

Coal generation variances in prior ECAMs were significantly larger than the 2022 ECAM variance of five percent. In the 2020 ECAM[6], actual coal generation decreased by 8,465,194 MWh on a total-company basis, or 22 percent compared to the forecast base period (calendar year 2016). In the 2021 ECAM[7] actual coal generation decreased by 7,509,751 MWh on a total-company basis, or 19 percent compared to the forecast base period as shown below in Table 4.2:

[6] *In the Matter of Rocky Mountain Power's Application Requesting Approval of $16.1 Million Net Power Cost Deferral (ECAM)*, Case No. PAC-E-21-09. Base NPC for the 2020 ECAM were based on 2015 annual results of operations report and established *In the Matter of Rocky Mountain Power to Update the Base Net Power Costs and Implement a Rate Stability Plan*, Case No. PAC-E-16-12, Application at 5.
[7] *In the Matter of Rocky Mountain Power's Application Requesting Approval of $28.4 Million ECAM Deferral*, Case No. PAC-E-22-05. Base NPC for the 2021 ECAM were based on 2015 annual results of operations report and established *In the Matter of Rocky Mountain Power to Update the Base Net Power Costs and Implement a Rate Stability Plan*, Case No. PAC-E-16-12, Application at 5.

Table 4.2 – Coal Generation – Forecast Base to Actual 2020-2022

Year	Base MWh	Actual MWh	Variance	Percent
2020 ECAM	**39,100,008**	**30,634,813**	**(8,465,194)**	**(22%)**
2021 ECAM	**39,100,008**	**31,590,257**	**(7,509,751)**	**(19%)**
2022 ECAM	**29,875,118**	**28,390,981**	**(1,484,137)**	**(5%)**

The large variances in the 2020 ECAM and the 2021 ECAM are also within the expected range and reflect the fact that the periods being compared are four to five years apart as well as the fact that Cholla Unit 4 was retired and Naughton Unit 3 was converted to gas after the 2016 forecast base period.

As shown in Table 4.3 below, natural gas generation in the 2022 ECAM increased by 5,198,076 MWh on a total-company basis, or 61 percent compared to the forecast base period:

Table 4.3 – Gas Generation – Forecast Base to Actual 2022

Plant	Base MWh	Actual MWh	Variance	Percent
Chehalis	2,182,201	2,171,994	(10,207)	(0%)
Currant Creek	993,561	2,805,979	1,812,418	182%
Gadsby	123,088	118,821	(4,267)	(3%)
Hermiston	1,049,262	1,433,878	384,616	37%
Lake Side 1	1,487,154	3,047,188	1,560,034	105%
Lake Side 2	2,143,135	3,531,485	1,388,350	65%
Naughton - Gas	509,100	576,231	67,131	13%
Total Gas	**8,487,500**	**13,685,576**	**5,198,076**	**61%**

When compared to prior ECAMs, the natural gas generation variance in the 2022 ECAM was significantly larger. The 2020 ECAM actual natural gas generation decreased by 307,312 MWh on a total-company basis, or two percent compared to the forecast base period. The 2021 ECAM natural gas generation increased by 962,582 MWh on a total-company basis, or eight percent compared to the forecast base period as shown below in Table 4.4. These variances are also within the expected ranges.

Table 4.4 below also shows that actual natural gas generation from 2020 to 2022 increased by 1,643,774 MWh or about 14 percent. Given the coal supply limitations the Company endured in calendar year 2022, along with the extreme weather events, ongoing drought, and increased load, it would be expected that gas generation would increase in actual system operations. This is especially true when natural gas generation is still a more economical resource compared to market purchases, on average.

Table 4.4 – Natural Gas Generation – Forecast Base to Actual 2020-2022

Year	Base MWh	Actual MWh	Variance	Percent
2020 ECAM	12,349,114	12,041,802	(307,312)	(2%)
2021 ECAM	12,349,114	13,311,696	962,582	8%
2022 ECAM	8,487,500	13,685,576	5,198,076	61%

5.0 Forecast Method and Optimization Models

The Base NPC from the 2021 GRC set the forecast for calendar year 2022 and the 2022 ECAM's NPC differential is the difference between that 2021 Base NPC and the 2022 Actual NPC. In calendar year 2022:

1. Wholesale electricity market prices were approximately 82 percent higher than the wholesale electricity market prices assumed in the 2021 Base NPC.

2. Natural gas market prices were approximately 151 percent higher than the natural gas market prices assumed in the 2021 Base NPC.

3. Hydroelectric generation (water availability) was approximately 34 percent lower than the hydroelectric generation assumed in the 2021 Base NPC.

NPC are sensitive to underlying commodity prices outside of the Company's control, and these commodity prices are wholesale electricity market prices, natural gas market prices and coal fuel prices. Regional wholesale electricity market prices are driven by regional natural gas market prices and calendar year 2022 natural gas market prices saw an unexpected increase due to various regional and national events such as the conflict in the Ukraine. Furthermore, unanticipated drought conditions in the Pacific Northwest decreased expected hydroelectric generation which diminished local and regional energy supply. Coal fuel is discussed in detail in Sections 6.0, 7.0, and 8.0 of this Investigative Report.

Additionally, global supply chain constraints delayed production and transportation of key components and equipment necessary for renewable resource construction across the nation. In the planning arena, at the regional level, renewable resource construction/acquisition is assumed to partially offset the impact of thermal plant retirements on an energy basis. In the short term, while the construction of these renewable resources are delayed, the thermal plant retirements are, however, proceeding as scheduled. The resulting energy shortfall decreases supply without any associated decrease in demand (load). Consequently, this triggers an incremental energy price rise across the competitive regional wholesale electricity markets which is additive to the exacerbation caused by natural gas market price increases.

PacifiCorp relies on a least-cost optimization model to ensure the cost-effective fulfillment of its system obligations. This optimization model takes into consideration various factors such as load resource balance, generator characteristics, system obligations, fuel supply, and transmission limits to determine the most efficient unit dispatch schedule. Due to expected variations between input forecasts and actual real-time operating conditions, market traders use the modeled results as a guide when making decisions on how to best economically serve the system obligations. This approach enables PacifiCorp to economically meet its obligations through coal generation, other resources, or market purchases.

Regarding the economic dispatch of coal units in calendar year 2022, PacifiCorp's least-cost optimization model and the California Independent System Operator's Western Energy Imbalance Market optimization model both accounted for the challenges related to coal supply. 2022 witnessed historically low coal inventories and surging natural gas prices, necessitating additional purchases of coal to meet immediate consumption needs and replenish depleted inventories.

6.0 PacifiCorp's Coal Acquisition Process

PacifiCorp's goal in acquiring fuel supply for the coal generating plants is to secure the least-cost and least-risk fuel for customers. To achieve this, the Company follows a comprehensive fuel supply planning process. It begins with estimating the annual and future generation forecast for each coal plant, considering many factors including historical usage patterns, the Company's sales and load forecasts, coal, power, and gas market price forecasts, changes in available generation throughout the Company's system and neighboring areas, operating lives of coal plants and other generating plants, and operational and regulatory reliability requirements. Subsequently, the Company then develops fuel volume, pricing, and sourcing assumptions, as well as transportation costs. If applicable, operating and capital costs for the plant are considered. In cases where a coal generating plant is supplied by a dedicated, jointly-owned mine, PacifiCorp collaborates with other owners to develop a mine plan to support the long-term fueling forecast. All costs from all sources are combined and evaluated to establish a fueling plan that is least-cost and least-risk.

The Company negotiates with third-party suppliers to secure fuel contracts to meet its generation forecasts in a manner that is least-cost and least-risk. PacifiCorp's process for developing and negotiating these contracts considers a range of important factors, including contract term, price, volume, supplier credit worthiness, plant location or coal region, coal supply options, coal transportation options, and coal quality. It is important to note that coal contracts can vary in length and are often renewed or replaced on a rolling basis. The forecasts used for one contract may differ from those used for another contract executed on a different date. Furthermore, subsequent contracts are often negotiated during different market conditions, given the ever-changing nature of the coal market.

It is also important to recognize that coal quality specifications vary across different regions, and transportation costs play a significant role in the overall fuel procurement process. Moreover, PacifiCorp's coal plants are situated in diverse geographic locations throughout the Western United States in strategic locations, typically adjacent to or near coal sources to minimize transportation costs. This diversity serves to reduce overall system risk since there may be locations where transportation, labor, or supplies may be limited for a given time, yet other locations may not have those same limitations. Given these factors, PacifiCorp considers term, price, volume, and coal quality when negotiating third-party CSAs and seeks to strike the optimum balance among these factors. Negotiations for bilateral CSAs are specific to the individual plant, mine or mines that can serve the plant, transportation requirements, and overall coal market.

CSAs play a vital role in ensuring reliable, uninterrupted supply of coal that will be available to fuel the Company's plants at known and predictable prices, terms, and conditions. In contrast, relying solely on spot market purchases to supply its plants poses significant risks. Relying exclusively on the spot market is an extremely risky strategy because it would expose customers to substantial and unreasonable price and supply risk, especially in the illiquid markets in which most of PacifiCorp's coal plants are located. On the other hand, multi-year contracts significantly reduce the risk to customers associated with market price volatility or fluctuations. It is also critical to emphasize that without the security of fuel supply contracts, there may be an elevated risk of fuel shortages during certain times of the year.

7.0 Changes in Coal Market Conditions

The coal market has experienced unprecedented price increases and significant fluctuation since 2021 including but not limited to: increased coal demand due to high domestic natural gas prices; nationwide low inventories at coal-fired power plants; increased demand abroad for coal exports; international and domestic supply chain constraints; labor and material shortages; and general market inflation.

Due to the record-high coal prices in export markets, many United States coal mines, including coal mines in Utah, rushed to take advantage of record high coal prices by exporting coal, or by leveraging increased prices in the domestic market. Additionally, the Lila Canyon mine fire that occurred in September 2022 compounded the supply and demand imbalance in the Utah coal market. The Lila Canyon mine accounted for more than 25 percent of Utah's total coal production in recent years. In November 2023, PacifiCorp was informed that the Lila Canyon mine will not be resuming coal production.

Also in calendar year 2022, the Company received force majeure claims from its two major Utah coal suppliers: (1) Bronco Utah Operations, LLC ("Bronco") on June 22, 2022, and (2) Wolverine Fuels, LLC ("Wolverine") on September 22, 2022. These two force majeure claims are attached to this Investigative Report as Confidential Exhibit No. 2. To manage the shortfalls in coal deliveries caused by the force majeure claims, PacifiCorp evaluated the merits of the claims and considered the legal options available to it under its CSAs. In July 2022, the Company began transporting coal from the Rock Garden safety pile for consumption at the Huntington plant to compensate for reduced coal deliveries. The Company also began working with current suppliers on potential solutions and new potential Utah coal suppliers to secure additional coal and began exploring alternative coal sources.

Therefore, to acquire additional coal, PacifiCorp issued a request for proposals ("2022 RFP") on August 31, 2022. The 2022 RFP was provided to all of the logical mine suppliers, a total of seven entities. After analyzing the proposals received, PacifiCorp accepted two proposals and negotiated agreements with Gentry Mountain Mining, LLC ("Gentry") and Wolverine for deliveries during 2023 through 2025. The 2022 RFP results demonstrate both the limited availability of coal in 2022 and the significant price increases in the current coal market for the shorter-term CSAs. The Company also initiated evaluations for (and continues to evaluate) potential acquisition of coal sourced from outside of Utah.

The Hunter and Huntington plants lack rail infrastructure for receiving out-of-state coal by rail. This lack of adequate off-loading rail infrastructure limits PacifiCorp's ability to procure and receive coal from outside of the state of Utah. Notwithstanding this limitation, the Company invited coal and transportation suppliers both inside and outside of Utah to participate in the 2022 RFP to explore the feasibility of alternative coal supply options.

The Company also explored the possibility of using the Company's own mines – Bridger mine in Wyoming and Trapper mine in Colorado – to cost-effectively supply the Hunter plant. However, due to coal supply needs at the Jim Bridger and Craig plants, additional coal was not available to ship to Utah. Furthermore, the Company is working with several non-conventional coal sources, including coal previously categorized as refuse, to supplement the fuel supply and continues to look for innovative ways to increase fuel supply at both the Hunter and Huntington plants.

Confidential Table 7.1 below provides the details of the force majeure claims by the Utah coal suppliers:

Confidential Table 7.1 – Force Majeure Claims in 2022

Plant	Supplier	Tons Under Contract	Tons Delivered	Variance	Explanation
Hunter	Wolverine	[redacted]	1,831,679	[redacted]	[redacted]
	Bronco	[redacted]	727,689	[redacted]	[redacted]
	Other		14,343	14,343	
		[redacted]	2,573,711	[redacted]	
Huntington	Wolverine	[redacted]	1,966,980	[redacted]	[redacted]
Total		[redacted]	4,540,691	[redacted]	

The coal supply constraints discussed above resulted in lower than forecasted coal deliveries at both the Huntington and Hunter plants in 2022. PacifiCorp's stockpiled inventories in Utah were significantly depleted. The Company anticipates there will be a continuation of coal supply shortages and market instability in the foreseeable future. Moreover, received and consumed coal quantities at the Utah plants will likely remain approximately the same in upcoming years until additional coal can be secured. Confidential Table 7.2 below provides a comparison of 2022 actuals, consumed and contracted coal quantities for both Hunter and Huntington plants:

Confidential Table 7.2 – 2022 Utah Plants Coal Delivered and Consumed

Plant	Contracted Tons	Delivered Tons	Consumed Tons	Inventory Tons Used
Hunter	[redacted]	2,573,711	3,303,195	729,484
Huntington	[redacted]	1,966,980	2,520,067	553,087
Total	[redacted]	4,540,691	5,823,262	1,282,571

As illustrated in Table 7.3 below, PacifiCorp began the year 2022 with 132 days of coal inventory and ended with 65 days of inventory at the Utah plants based upon expected consumption of 7.0 million tons:

Table 7.3 – 2022 Utah Plants Coal Inventory

	Utah Plants Inventory		2022 Tons Consumed	Beginning Inventory as Expected Days Burn	Ending Inventory as Expected Days Burn
	12/31/2021 Tons	12/31/2022 Tons			
Hunter	1,243,842	514,358	3,303,195	114	47
Huntington	473,092	436,165	2,520,067	58	53
			5,823,262		
			Transferred to Huntington		
Rock Garden Safety Pile	817,837	298,796	519,041	100	36
Total Utah	2,534,771	1,249,319		132	65

PacifiCorp began reducing generation at the Hunter plant in September 2022 and at the Huntington plant in November 2022 to maintain stockpile reliability targets. Based upon industry standard practice regarding the dispatch of fuel-limited resources, such as hydro plants, PacifiCorp calculated the dispatch price for the fuel-limited Hunter and Huntington units to maintain prudent and reliable coal stockpile inventories and secure plant availability for the benefit of customers during critical periods when the plants were most needed. This calculation rendered the Hunter and Huntington plants less economically favorable to dispatch within the operational optimization model. However, these actions were necessary and the Hunter and Huntington plants were dispatched appropriately in comparison to other generating resources.

8.0 Coal Supply Agreements

PacifiCorp purchased coal for its nine coal-fueled plants under 14 different CSAs during calendar year 2022. The Company entered into one new CSA, and one amendment of a previously executed CSA, for 2022. Prior to entering into a CSA, the Company conducts a detailed internal economic analysis to determine whether the CSA is a reasonable and prudent business decision and in the best interest of its customers. Generally, these economic analyses include background on each plant, key contracting provisions, discussion of modeling inputs and assumptions, and analyses of various scenarios ran under current and forecasted conditions. These analyses are consistent with the Company's integrated resource planning ("IRP") processes and rely on software to estimate the expected cost or benefit of each new CSA compared to relevant alternatives. The 14 CSAs are listed in Table 8.1 below:

Table 8.1 – Existing, Amended, and New CSAs in 2022

Plant	Supplier/Mine	Contract Type	Executed	Term
Naughton	Kemmerer Operations/Kemmerer	Existing CSA	12/29/21	Jan 2022 - Dec 2025
Wyodak	Wyodak Resources / Wyodak	Existing CSA	01/01/01	Jan 2001 - Dec 2022
Dave Johnston	Arch / Coal Creek	Existing CSA	08/20/19	Jan 2020 - Dec 2022
Dave Johnston	Peabody / Caballo	Existing CSA	09/17/19	Jan 2020 - Dec 2022
Dave Johnston	Peabody / NARM	Existing CSA	11/12/20	Jan 2021 - Dec 2024
Dave Johnston	Peabody / Caballo	Existing CSA	12/08/20	Jan 2021 - Dec 2024
Hunter	Bronco / Emery	2nd Amendment	08/03/22	Aug 2022 - Dec 2022
Hunter	Wolverine Fuels	Existing CSA	12/11/20	Jan 2021 - Dec 2023
Huntington	Wolverine / Sufco & Skyline	Existing CSA	12/12/14	Jun 2015 - Dec 2029
Jim Bridger	Lighthouse Resources / Black Butte	Existing CSA	02/28/18	Jan 2018 - Jun 2022
Jim Bridger	Lighthouse Resources / Black Butte	New	06/17/22	Jun 2022 - Dec 2023
Colstrip	Westmoreland/Rosebud	Existing CSA	12/05/19	Dec 2019 - Dec 2024
Craig	Trapper Mining/Trapper	Existing CSA	01/01/21	Jan 2021 - Dec 2025
Hayden	Peabody/Twentymile	Existing CSA	12/12/11	Jan 2012 - Dec 2027

The Company is focused on achieving its target coal supply at a reasonable price, along with contract terms that provide flexibility. PacifiCorp continuously re-evaluates the practice of maintaining flexibility in its fuel's supply options and generation planning strategies, with each new CSA to determine whether a longer or shorter term would benefit its customers and maintain generation. Each CSA typically has a minimum-take or similar contracting provision which is a fundamental component of most CSAs and constitutes the consideration required to obtain a supplier's commitment to provide coal.

8.1 Utah Plants

8.1.1 Hunter Plant

The Hunter plant is located near Castle Dale, Utah, in Emery County. The plant is supplied with coal from Wolverine, Bronco and Gentry. The coal is delivered to the plant by trucks. It has operated three coal units since opening in 1978. The combined rated capacity for the three units is 1,363 MW. PacifiCorp owns 93.75 percent of Hunter Unit 1, 60.31 percent of Hunter Unit 2, and 100 percent of Hunter Unit 3, for a combined 84.97 percent or 1,158 MW. Deseret Generation & Transmission, Utah Association of Municipal Power Systems and Utah Municipal Power Agency are the Hunter plants' co-owners. Historically, PacifiCorp has purchased 100 percent of Hunter's coal requirements from local mines. The co-owners then purchase their coal requirements from PacifiCorp based on their actual coal consumption. PacifiCorp's 2023 IRP calls for Hunter Unit 1 to cease burning coal on December 31, 2031, and for Hunter Unit 2 and Hunter Unit 3 to cease burning coal on December 31, 2032.

The total amount of coal under contract for the Hunter plant in 2022 was **[Begin Confidential]** [redacted] **[End Confidential]** tons. However, PacifiCorp did not receive the full amount of coal supply under its existing CSAs for the Hunter plant due to the force majeure claims, transportation issues, mine geologic difficulties and other challenges in the Utah coal market. The contracted volume was also more than the actual coal consumed at Hunter in 2022, which included a significant portion of the available stockpiled inventory.

8.1.2 Huntington Plant

The Huntington power plant is located near Huntington, in Emery County, Utah. As part of the closure of the Deer Creek Mine in 2014, which was the primary source of coal for the Huntington power plant, the Company executed a 15-year agreement with Wolverine to supply the Company's coal requirements for Huntington plant through December 2029. The expected annual quantity has a minimum purchase obligation of **[Begin Confidential]** [redacted] **[End Confidential]** tons of coal per year and a maximum supply obligation of **[Begin Confidential]** [redacted] **[End Confidential]** tons per year. The CSA has fixed pricing for the entire term of the contract and the CSA includes a minimum take provision.

Similar to the Hunter plant, PacifiCorp did not receive the full amount of coal supply under the existing CSA for the Huntington plant due to multiple factors such as: a force majeure claim, transportation issues, mine geologic difficulties and other challenges in the Utah coal market. Coal stockpiled at the Rock Garden safety pile was used to supplement the consumption at the Huntington plant.

8.2 Wyoming Plants

8.2.1 Jim Bridger Plant

The Jim Bridger plant is located approximately 24 miles east of Rock Springs, Wyoming. The Jim Bridger plant is the largest power plant on the PacifiCorp system (2,120 MW) and is jointly owned by PacifiCorp (66.7 percent) and Idaho Power Company ("IPC") (33.3 percent). The Jim Bridger plant consists of four almost identical units, each with a nominal 530 net MW capacity. Over the four-year period of 2019-2022, the Jim Bridger plant consumed 24 million tons of coal, an average of six million tons per year. The plant is designed to consume coal sourced from southwest Wyoming. PacifiCorp's 2023 IRP calls for Jim Bridger Unit 1 and Jim Bridger Unit 2 to cease burning coal on December 31, 2023, and convert to natural gas consumption. Jim Bridger Unit 3 and Jim Bridger Unit 4 are planned to cease burning coal on December 31, 2029, and convert to gas as well. The remaining useful life for all four Bridger units is forecasted to be December 31, 2037.

Ownership in the Bridger Coal Company allows PacifiCorp to flex coal deliveries up or down, within certain constraints, to better align Jim Bridger plant delivered and consumed coal quantities. Mine ownership also reduces coal supply delivery risk, mitigates unfavorable impacts of unexpected coal delivery changes, and has historically improved contract price terms with the third-party coal supplier.

PacifiCorp did not reduce generation at the Jim Bridger plant during calendar year 2022 due to a lack of coal supply. PacifiCorp's minimum stockpile reliability target for 2022 was deemed to be

530,000 tons or 45 days of expected consumption of 4.3 million tons. As illustrated in Table 8.2 below, PacifiCorp's inventory stockpile at Jim Bridger exceeded that target throughout 2022:

Table 8.2: 2022 Jim Bridger Coal Inventory

	Jim Bridger Plant Inventory				2022 Tons Consumed	Beginning Inventory as Expected Days Burn	Ending Inventory as Expected Days Burn
	12/31/2021		12/31/2022				
	Tons	%	Tons	%			
PacifiCorp	1,008,008	78%	718,623	90%	4,215,793	86	61
Idaho Power	276,559	22%	79,160	10%	1,885,327	54	15
Total Plant	1,284,567	100%	797,783	100%	6,101,120	76	47

Note: PacifiCorp's Days Burn is calculated using Expected 2022 Consumption of 4.3 million tons. Idaho Power's Days Burn is calculated using actual 2022 consumption.

Being the 67 percent owner of the Jim Bridger plant, PacifiCorp is responsible for supplying its ownership portion of the coal directly to the plant. PacifiCorp prudently managed its coal inventory in 2022 by beginning the year with just over one million tons of coal which equated to 78 percent of the coal at the plant. PacifiCorp ended the calendar year 2022 with a supply of approximately 719,000 tons which equated to 90 percent of the coal inventory. The Company entered 2022 with enough coal to be able to draw from its coal stockpile without placing inventory at a level that could have jeopardized reliability for its customers.

PacifiCorp's coal inventory exceeded its minimum stockpile reliability target of 45 days of inventory throughout 2022. There was no need for PacifiCorp to reduce generation at the Jim Bridger plant in 2022 to conserve coal. Thus, PacifiCorp did not reduce generation in 2022 to conserve coal inventory at the Jim Bridger plant. As shown in Confidential Table 8.3 below, the coal supply shortfall experienced at Jim Bridger did not reach a level critical enough for PacifiCorp to take measures to reduce generation in 2022:

Confidential Table 8.3: 2022 Jim Bridger Coal Supply (PacifiCorp Share)

Plant	Supplier	Budgeted Tons	Delivered Tons	Variance	Explanation
Bridger	Bridger Coal Company	2,653,333	2,648,039	(5,294)	
	Black Butte Coal Company	[redacted]	1,278,948	[redacted]	
			3,926,987		

It is important to recognize the distinction between the situations faced by PacifiCorp and IPC in 2022 concerning coal supply issues and the resulting generation curtailment at the Jim Bridger plant. Through proactively managing its coal supply, PacifiCorp successfully avoided the need to reduce generation to ensure an adequate coal stockpile availability to meet reliability standards. Specifically, PacifiCorp took the following actions to ensure an adequate coal supply at Jim Bridger for the relevant time-period:

- In August 2022, PacifiCorp directed the plant to begin using coal permitted for long-term storage. A total of 407,395 tons (shared between PacifiCorp and IPC) were consumed from the long-term storage pile in 2022.

- In September 2022, PacifiCorp issued an RFP to Powder River Basin ("PRB") coal suppliers for future deliveries to the plant, specifically targeting deliveries for the fourth quarter of 2022 and 2023.

- In September 2022, PacifiCorp initiated discussions with Union Pacific railroad regarding the delivery of PRB coal to the plant. These discussions aimed to ensure reliable transportation and delivery of the required coal to Jim Bridger plant.

- PacifiCorp also embarked on a search to lease 120 coal railcars, further demonstrating its commitment to securing adequate transportation resources for coal deliveries.

These proactive actions ultimately led to the successful delivery of PRB coal to the Jim Bridger plant, commencing in April 2023. By taking these steps, PacifiCorp effectively managed its coal supply and ensured the availability of coal for the Jim Bridger plant, ensuring benefit to its customers. These measures highlight PacifiCorp's continuous proactive approach to addressing the unprecedented coal supply challenges that occurred in 2022 while maintaining reliable generation.

8.2.2 Naughton Plant

The Naughton plant is located in Kemmerer, Wyoming, and is wholly owned by PacifiCorp. Naughton is supplied by the adjacent Kemmerer mine with Naughton Unit 1 and Naughton Unit 2, rated at 156 and 201 MW, operated on coal and Naughton Unit 3 operates on natural gas. PacifiCorp's 2023 IRP identifies that Naughton Unit 1 and Naughton Unit 2 will cease burning coal on December 31, 2025, and convert to gas in 2026. PacifiCorp's prior agreement for Naughton's coal supply ended on December 31, 2021. PacifiCorp executed a new CSA with the Kemmerer Mine for the purchase of Naughton's coal supply from January 1, 2022 through December 31, 2025.

8.2.3 Dave Johnston Plant

The Dave Johnston plant is located in Glenrock, Wyoming. PacifiCorp owns 100 percent of the plant and operates all four units. The output capacity at the plant is as follows: Dave Johnston Unit 1 – 99 MW; Dave Johnston Unit 2 – 106 MW; Dave Johnston Unit 3 – 220 MW; and Dave Johnston Unit 4 – 330 MW. The plant receives coal from mines in the PRB which is the largest coal production region in the U.S. Due to the abundance of coal in the PRB, along with the number of operating mines in this region, PacifiCorp is able to take advantage of favorable coal market pricing that exists in the liquid PRB market. The coal is delivered by Burlington Northern Santa Fe Railway. During 2022 there were four CSAs; one with Arch Coal's Coal Creek Mine and three with Peabody Energy for deliveries from the Caballo mine and North Antelope Rochelle mine.

8.2.4 Wyodak Plant

The Wyodak plant is located in Campbell County, Wyoming, and is jointly owned with Black Hills Energy ("Black Hills"), which has a 20 percent ownership interest in the plant. There is one coal unit at the Wyodak plant with an output capacity of 335 MW. The Wyodak plant is a mine-mouth operation and receives its coal from the adjacent Wyodak Mine by conveyor. This eliminates the need to store coal inventory at the plant. Wyodak Resources Development Corp. (a subsidiary of Black Hills) owns and operates the mine. PacifiCorp's agreement for the Wyodak plant's coal supply was from January 1, 2001, to December 31, 2022. A new CSA for Wyodak was signed in 2022 for coal supply beginning in 2023.

8.3 Joint-Owned Plants – Partner Operated

8.3.1 Colstrip Plant

The Colstrip plant is a 1,480 MW two-unit coal plant located in Colstrip, Montana. Colstrip Unit 3 and Colstrip Unit 4 are jointly owned by Avista Corporation, NorthWestern Energy, PacifiCorp, Portland General Electric Company, Talen Energy, and Puget Sound Energy.

Colstrip Unit 1 and Colstrip Unit 2 were retired in 2020 and were owned by Talen Energy and PSE. The plant is a mine-mouth operation and receives its coal from the adjacent Rosebud Mine by conveyor. Westmoreland Rosebud Mining, LLC owns and operates the mine. PacifiCorp's agreement for the Colstrip plant coal supply is from January 1, 2020, through December 31, 2024, with an option for PacifiCorp to extend it through December 31, 2025.

8.3.2 Craig Plant

The Craig plant is a 1,427 MW, three-unit coal plant located in Moffat County, Colorado. Craig Unit 1 and Craig Unit 2 are jointly owned by Tri-State Generation and Transmission Association ("Tri-State"), Salt River Project Agricultural Improvement and Power District ("SRP"), Platte River Power Authority ("Platte"), PacifiCorp and Public Service Company of Colorado ("PSCo"). Craig Unit 3 is owned exclusively by Tri-State. Craig Unit 1 and Craig Unit 2 are supplied by the Trapper mine, which is an affiliate captive mine owned by three entities with the ownership percentages as follows: SRP – 43.72 percent, PacifiCorp – 29.14 percent, and Platte – 27.14 percent. The recent CSA between Trapper mine and PacifiCorp, SRP and Platte was for a term of 10 years, from January 1, 2010, through December 31, 2020, which was later extended for another five years through December 31, 2025.

8.3.3 Hayden Plant

The Hayden plant is a 441 MW, two-unit coal plant located in Routt County, Colorado. Hayden Unit 1 is jointly owned by PSCo and PacifiCorp. The Company owns 24.5 percent of Hayden Unit 1. Hayden Unit 2 is jointly owned by PSCo, SRP, and PacifiCorp. The Company owns 12.6 percent of Hayden Unit 2. PSCo operates the plant. PacifiCorp negotiated the Hayden CSA in collaboration with PSCo and SRP in order to secure future fuel requirements for Hayden from the nearby Twentymile mine owned and operated by Peabody Energy. The Hayden CSA was executed on December 12, 2011, and runs through December 31, 2027. Hayden Unit 2 is scheduled for closure in 2027 and Hayden Unit 1 is scheduled for closure in 2028.

9.0 Conclusion

In compliance with Order No. 35801, the Company respectfully submits this Investigative Report focused on the issues related to lower coal generation and coal supplies, the deployment of its coal fleet, and the Company's management of these issues during 2022.

As shown in this Investigative Report in detail, the actual coal generation in the 2022 ECAM was reasonable and in best interest of its customers, and the Company operated prudently based on market conditions that were influenced by multiple factors including but not limited to, the war in the Ukraine and extreme weather events. The Company was also challenged by force majeure events outside of its control, but the Company was properly prepared for these events with sufficient stockpile supplies at both the Hunter and Huntington plants as well as the Rock

Garden safety pile. Faced with force majeure events, the Company took proactive measures to deploy its coal fleet prudently by working to secure additional coal while prudently managing its coal supply to ensure its coal fleet reliability was maintained. Despite facing numerous challenges in 2022 as detailed in this Investigative Report, the difference between actual and the forecast coal generation was only five percent.

The Company respectfully request that the Commission issue an order finding that the Company complied with the requirements in Order No. 35801 and costs within the 2022 ECAM deferral were prudently incurred.

Confidential Exhibit No. 1

2022 Thermal Outage Summary

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Confidential Exhibit No. 2

Force Majeure Claims

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Rocky Mountain Power
Exhibit RMP___(JP-2R)
Docket No. 23-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Rebuttal Testimony of Jack Painter

Discovery Responses

January 2024

23-035-01 / Rocky Mountain Power
June 23, 2023
DPU Data Request 3.9

DPU Data Request 3.9

Painter work paper Attachment B, (2.5) Actual NPC – Coal Generation

(a) For each coal plant, provide the generation capacity percentage that each plant operated at on a monthly basis during 2022.

Response to DPU Data Request 3.9

The Company assumes that the reference to "Attachment B" is intended to be a reference to the confidential work papers supporting the direct testimony of Company witness, Jack Painter, specifically confidential file "23-035-01 RMP EBA PROPRIETARY Painter Workpapers and Exhibit (5-1-23)". Based on the foregoing assumption, the Company responds as follows:

Please refer to the Company's response to DPU Data Request 3.7 subpart (d).

Attachment DPU 3.7-2

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Generation Capacity Percentage												
Colstrip	98%	88%	96%	46%	57%	73%	89%	95%	83%	97%	92%	87%
Craig	89%	69%	79%	78%	83%	79%	80%	88%	84%	67%	56%	42%
Dave Johnston	51%	55%	63%	33%	42%	48%	67%	59%	69%	59%	59%	46%
Hayden	96%	85%	71%	73%	54%	70%	83%	86%	76%	73%	80%	89%
Hunter	77%	66%	38%	50%	70%	75%	82%	82%	57%	24%	32%	47%
Huntington	80%	73%	69%	72%	68%	65%	78%	85%	81%	42%	67%	75%
Jim Bridger	52%	51%	58%	54%	51%	42%	74%	73%	72%	76%	60%	54%
Naughton 1 & 2	78%	36%	34%	32%	42%	43%	76%	78%	71%	79%	66%	84%
Wyodak	41%	67%	63%	37%	0%	61%	68%	84%	63%	80%	61%	60%
Generation Capacity Percentage												
Chehalis	25%	32%	17%	46%	0%	1%	40%	52%	55%	66%	66%	65%
Currant Creek	50%	52%	45%	49%	37%	45%	44%	50%	48%	49%	55%	54%
Gadsby	0%	0%	0%	1%	3%	6%	14%	16%	10%	8%	4%	4%
Gadsby CT	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	1%
Hermiston	66%	71%	67%	73%	65%	53%	62%	71%	71%	2%	79%	77%
Lake Side 1	55%	53%	35%	48%	46%	40%	44%	44%	52%	51%	54%	57%
Lake Side 2	58%	55%	46%	36%	37%	49%	50%	57%	57%	52%	61%	62%
Naughton 3	-1%	-1%	-1%	20%	35%	28%	41%	48%	32%	42%	29%	44%
Actual 2022 Coal Generation												
Colstrip	107,678	87,452	105,735	48,902	62,976	77,595	97,988	104,136	88,209	106,452	97,850	95,504
Craig	108,532	75,241	96,037	91,615	101,070	92,495	97,178	106,523	98,884	81,659	66,178	51,328
Dave Johnston	283,360	279,895	352,246	179,372	232,052	260,040	375,475	331,823	376,401	333,904	319,605	257,746
Hayden	54,717	43,930	40,635	40,025	30,587	38,746	47,276	48,776	41,692	41,725	44,323	50,640
Hunter	656,821	506,717	327,003	410,902	599,263	624,207	702,793	699,341	468,828	203,151	263,034	403,700
Huntington	539,332	445,621	464,080	471,297	460,886	424,855	526,211	577,934	530,885	286,250	438,440	507,324
Jim Bridger	546,236	480,878	604,740	544,518	533,351	428,698	778,834	763,054	731,146	794,713	609,341	560,608
Naughton 1 & 2	206,569	85,854	91,274	81,841	111,446	109,973	202,574	206,453	181,769	208,890	170,734	222,593
Wyodak	83,550	121,866	127,375	72,711	2	116,808	133,987	166,814	121,240	157,634	119,935	121,889
Actual 2022 Gas Generation												
Chehalis	125,384	139,501	80,614	212,498	(471)	2,871	182,021	236,233	245,562	315,880	311,140	320,761
Currant Creek	257,090	241,372	226,708	234,162	179,358	213,110	209,454	239,479	224,078	239,252	266,306	275,610
Gadsby	(243)	114	(301)	1,316	5,282	10,124	25,588	28,087	16,948	14,317	6,632	7,609
Gadsby CT	(25)	258	128	187	(149)	(24)	890	696	867	46	13	461
Hermiston	130,938	124,670	128,862	135,930	125,118	98,816	118,302	134,845	132,717	4,573	148,272	150,835
Lake Side 1	300,761	261,431	188,443	243,628	246,617	205,676	236,227	233,974	272,646	268,152	280,946	308,687
Lake Side 2	347,014	295,783	271,073	202,574	210,193	270,877	281,665	323,913	317,115	298,637	344,997	367,644
Naughton 3	(982)	(1,093)	(1,139)	35,775	64,962	49,784	74,617	87,751	56,501	77,175	52,526	80,354
Monthly Hours	744	672	743	720	744	720	744	744	720	744	721	744
Peak Capacity (Nameplate) (From GRC)	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
Colstrip	148	148	148	148	148	148	148	148	148	148	148	148
Craig	163	163	163	163	163	163	163	163	163	163	163	163
Dave Johnston	751	751	751	751	751	751	755	755	755	755	755	755
Hayden	77	77	77	77	77	77	77	77	77	77	77	77
Hunter	1,151	1,151	1,151	1,151	1,151	1,151	1,148	1,148	1,151	1,151	1,151	1,151
Huntington	909	909	909	909	909	909	909	909	909	909	909	909
Jim Bridger	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406
Naughton	357	357	357	357	357	357	357	357	357	357	357	357
Wyodak	272	272	272	272	266	266	266	266	266	266	272	272
Chehalis	662	657	651	647	635	631	615	613	622	646	657	663
Currant Creek	692	686	676	663	647	651	643	645	653	656	677	690
Gadsby	238	238	238	238	238	238	238	238	238	238	238	238
Gadsby CT	123	122	122	121	120	119	117	118	119	120	122	123
Hermiston	265	262	259	258	258	257	256	256	259	258	260	264
Lake Side 1	733	727	719	711	725	722	718	720	724	707	720	730
Lake Side 2	802	794	786	778	767	768	758	761	771	774	788	799
Naughton - Gas	247	247	247	247	247	247	247	247	247	247	247	247

23-035-01 / Rocky Mountain Power
October 26, 2023
DPU Data Request 17.1

DPU Data Request 17.1

(a) Provide PCI Optimization Model details that would detail, explain, and evaluate the generation dispatched and market purchases made during the month of September and December 2022. Indicate the reason for actual gas and coal generation and the amount of market purchases made.

(b) Indicate how each coal and gas plant is selected for distribution generally, and specifically for the months of September and December during peak load.

(c) Indicate what assumption on coal and gas pricing was used in determining generation generally, and specifically for the months of September and December during peak load.

Response to DPU Data Request 17.1

(a) The Company retains a daily archive of short-term PCI Energy Solutions (formerly Power Costs Incorporated) (PCI) optimization model results. These documents include a selection of hourly outputs such as the model's recommended unit dispatch, fuel consumption, transmission utilization, solar/wind/hydro forecasts, operating reserve requirements, load forecasts, and market transactions. Note: the results are not dispatch/trading instructions but are considered by traders when making decisions around unit commitment, resource scheduling, and market purchases/sales. Please refer to Confidential Attachment DPU 17.1 which provides copies of the archived short-term PCI model outputs for the requested period.

(b) The PCI optimization model receives the following data points as inputs: existing forward electricity transactions (standard product transactions and other contracts), forward energy prices, estimated market depth at each market hub, and solar, wind, and hydroelectric generation forecasts. Additionally, dispatchable units are modeled according to their physical characteristics such as heat rate curves, ramp rate, startup fuel, minimum generation, operating reserve carrying abilities, minimum on time, etc. The node and transmission topology can also be considered an input.

(c) The assumptions used for the dispatch price for coal and gas units is based on the fuel costs and variable operating expenses. The assumptions used in prior periods, such as September 2022 and / or December 2022, are not archived or retained in the PCI optimization model or by PacifiCorp in the ordinary course of business.

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rules R746-1-601–606.

REDACTED

23-035-01 / Rocky Mountain Power
October 26, 2023
DPU Data Request 17.2

DPU Data Request 17.2

Identify the generation and distribution constraints for coal and gas plants experienced by PacifiCorp in 2022 generally and specifically during the months of September and December 2022.

Confidential Response to DPU Data Request 17.2

Thermal generation plants can be constrained by outages both planned and unplanned, derates, coal supply issues, transmission constraints, and emission constraints.

[CONFIDENTIAL BEGINS] [redacted] **[CONFIDENTIAL ENDS]**.

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rules R746-1-601–606.

23-035-01 / Rocky Mountain Power
October 26, 2023
DPU Data Request 17.3

DPU Data Request 17.3

Provide a monthly comparison chart for the last 5 years (calendar years 2022 – 2018) detailing the coal reserve levels at each of the PacifiCorp coal generation units, indicating and including reserve locations used by each plant. Include the required reserve level for each month by location and provide a copy of the reserve requirement policy for this period with updates as enacted.

Response to DPU Data Request 17.3

The Company objects to this request seeking information for periods not relevant to the 2023 energy balancing account (EBA) for the deferral calendar year 2022 and which is unlikely to lead to admissible evidence in this 2023 EBA proceeding. Notwithstanding the foregoing objection, the Company responds as follows:

Please refer to Confidential Attachment DPU 17.3-1 which provides coal reserve levels by location for each plant, calendar years 2018 through 2022.

Please refer to Confidential Attachment DPU 17.3-2 which provides copies of PacifiCorp's Coal Inventory Policies and Procedures as listed below:

- Docket 18-035-07 – PacifiCorp's Coal Inventory Policies and Procedures updated March 20, 2018.
- Docket 19-035-07 – PacifiCorp's Coal Inventory Policies and Procedures updated March 14, 2019.
- Docket 20-035-12 – PacifiCorp's Coal Inventory Policies and Procedures updated March 13, 2020.
- Docket 21-035-12 – PacifiCorp's Coal Inventory Policies and Procedures updated March 18, 2021.
- Docket 22-035-22 – PacifiCorp's Coal Inventory Policies and Procedures updated March 22, 2022.

Note: the provided policy / procedure documents are the same documents that the Division of Public Utilities (DPU) reviews each year during its annual audit of PacifiCorp's fuel inventory management, policy, procedures and actual practices.

In addition, in Confidential Attachment DPU 17.3-2, the Company has included a copy of the most recent PacifiCorp's Coal Inventory Policies and Procedures updated March 10, 2023 (reviewed during the DPU's audit conducted earlier this year as part of Docket 23-035-14).

23-035-01 / Rocky Mountain Power
October 26, 2023
DPU Data Request 17.3

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rules R746-1-601–606.

23-035-01 / Rocky Mountain Power
October 26, 2023
DPU Data Request 17.4

DPU Data Request 17.4

On May 17, 2023, Rocky Mountain Power submitted reply comments to the Idaho Public Utilities Commission in Case No. PAC-E-23-09. Please provide all supporting work papers including confidential materials. Please provide a confidential (non-redacted) copy of the above referenced letter with the confidential table information viewable.

On May 31, 2023, the Idaho Public Utilities Commission filed its Order No. 35801 in Case No. PAC-E-23-09 wherein it requested a report on the issues causing the extraordinarily high NPC as follows "In order to ensure the Company was maximizing its coal fleet to customers' benefit, we direct the Company to investigate and report on the issues causing the extraordinarily high NPC, with a focus on the lack of coal generation and coal supplies, and the Company's management of those issues, as described in Staff's and P4's comments. This report should be completed before the end of the 2023 ECAM year". Provide a full copy (work papers, etc.) supporting RMP's response to this request and prepared for this report as soon as it is available, include any interim work papers and progress updates as soon as available.

Response to DPU Data Request 17.4

The Company objects to this request as outside the scope of this proceeding, and not reasonably calculated to lead to the discovery of admissible information. Notwithstanding the foregoing objection, the Company responds as follows:

Please refer to Confidential Attachment DPU 17.4 which provides a copy of the Company's confidential reply comments filed with the Idaho Public Utilities Commission (IPUC) in Case PAC-E-23-09 on May 17, 2023. The report requested in IPUC Order 35801 will be completed at the end of calendar year 2023.

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rules R746-1-601–606.

23-035-01 / Rocky Mountain Power
December 22, 2023
DPU Data Request 17.4 – 1st Supplemental

DPU Data Request 17.4

On May 17, 2023, Rocky Mountain Power submitted reply comments to the Idaho Public Utilities Commission in Case No. PAC-E-23-09. Please provide all supporting work papers including confidential materials. Please provide a confidential (non-redacted) copy of the above referenced letter with the confidential table information viewable.

On May 31, 2023, the Idaho Public Utilities Commission filed its Order No. 35801 in Case No. PAC-E-23-09 wherein it requested a report on the issues causing the extraordinarily high NPC as follows "In order to ensure the Company was maximizing its coal fleet to customers' benefit, we direct the Company to investigate and report on the issues causing the extraordinarily high NPC, with a focus on the lack of coal generation and coal supplies, and the Company's management of those issues, as described in Staff's and P4's comments. This report should be completed before the end of the 2023 ECAM year". Provide a full copy (work papers, etc.) supporting RMP's response to this request and prepared for this report as soon as it is available, include any interim work papers and progress updates as soon as available.

1st Supplemental Response to DPU Data Request 17.4

Further to the Company's response to DPU Data Request 17.4 dated October 26, 2023, the Company provides the following supplemental response:

The Company continues to object to this request as outside the scope of this proceeding, and not reasonably calculated to lead to the discovery of admissible information. Notwithstanding the foregoing objection, the Company responds as follows:

Please refer to Confidential Attachment DPU 17.4-1 1st Supplemental which provides a copy of the Company's 2022 Energy Cost Adjustment Mechanism (ECAM) Confidential Investigative Report filed with the Idaho Public Utilities Commission (IPUC) on December 22, 2023 pursuant to IPUC Case PAC-E-23-09, Order 35801.

Please refer to Confidential Attachment DPU 17.4-2 1st Supplemental which provides the supporting confidential work paper.

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rules R746-1-601–606.