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April 15, 2024

Monica Barrios-Sanchez, Secretary
Idaho Public Utilities Commission
11331 W. Chinden Blvd., Bldg 8,
Suite 201-A (83714)
PO Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-24-17
Application of Idaho Power Company for Authority to Implement Power Cost Adjustment ("PCA") Rates for Electric Service from June 1, 2024, through May 31, 2025

Dear Ms. Barrios-Sanchez:

Attached for electronic filing is Idaho Power Company's Application and Direct Testimony of Jessica G. Brady filed in support of the Application.

Attachment Nos. 3 and 6 to the Application and Exhibit Nos. 4 and 5 to the Direct Testimony of Jessica G. Brady contain confidential information and will be provided separately via an encrypted email to the parties who sign the Protective Agreement. A Word version of the testimony will also be sent in a separate email for the convenience of the Reporter.

Accompanying this filing is the Company's Press Release, Customer Notice, and Direct Mail Postcard.

If you have any questions about the attached documents, please do not hesitate to contact me.

Sincerely,

Megan Goicoechea Allen

Megan Goicoechea Allen

MGA:sg
Enclosures

CERTIFICATE OF ATTORNEY

ASSERTION THAT INFORMATION CONTAINED IN AN IDAHO PUBLIC UTILITIES COMMISSION FILING IS PROTECTED FROM PUBLIC INSPECTION

Idaho Power Company's Application for Authority to Implement Power Cost Adjustment ("PCA") Rates for Electric Service from June 1, 2024 through May 31, 2025

Case No. IPC-E-24-17

The undersigned attorney, in accordance with Commission Rules of Procedure 67, believes that Attachment Nos. 3 and 6 to Idaho Power Company's Application for Authority to Implement Power Cost Adjustment Rates for Electric Service from June 1, 2024 through May 31, 2025 and Exhibit Nos. 4 and 5 to the Direct Testimony of Jessica G. Brady, dated April 15, 2024, may contain information that Idaho Power Company and a third-party claim constitutes confidential trade secrets, proprietary information, and/or private business records required by law to be submitted to or inspected by a public agency as described in *Idaho Code* § 74-101, *et seq*., and § 48-801, *et seq*., or is otherwise protected from public disclosure and as such is exempt from public inspection, examination, or copying.

DATED this 15th day of April 2024.

Megan Goicoechea Allen

Megan Goicoechea Allen
Counsel for Idaho Power Company

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Attorneys for Idaho Power Company

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT ("PCA") RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2024, THROUGH MAY 31, 2025.	)	CASE NO. IPC-E-24-17 APPLICATION

Idaho Power Company ("Idaho Power" or "Company"), in accordance with *Idaho Code* § 61-502 and Commission Rule of Procedure[1] 52, hereby respectfully requests the Idaho Public Utilities Commission ("Commission") approve an update to Schedule 55 based on the quantification of the 2024-2025 Power Cost Adjustment ("PCA") to become effective June 1, 2024, for the period of June 1, 2024, through May 31, 2025. If the proposed rates and charges for electric service in the state of Idaho included as

[1] Hereinafter cited as RP.

Attachment 1 to this Application are approved, the 2024-2025 PCA will result in an overall revenue decrease of approximately $35.7 million, or a 2.31 percent decrease from current billed revenue.

In support of this Application, Idaho Power has filed the Direct Testimony of Jessica G. Brady, Senior Regulatory Analyst ("Brady Testimony"). Ms. Brady's testimony provides an overview of the PCA, details the 2024-2025 PCA amount, explains the factors that impact this year's PCA quantification, presents the calculation of the proposed 2024-2025 PCA rates, and discusses the additional PCA component related to revenue sharing. In addition, the Brady Testimony details the net customer impact of the 2024-2025 PCA rates if approved as filed and addresses compliance with prior Commission Orders. In further support of this Application, Idaho Power represents as follows:

I. BACKGROUND

1. Idaho Power is an Idaho corporation whose principal place of business is 1221 West Idaho Street, Boise, Idaho 83702.

2. Idaho Power is a public utility supplying retail electric service to more than 600,000 customers in southern Idaho and eastern Oregon. Idaho Power is subject to the jurisdiction of this Commission in Idaho and to the jurisdiction of the Public Utility Commission of Oregon. Idaho Power is also subject to the jurisdiction of the Federal Energy Regulatory Commission.

3. The Company is compensated for "normal" costs of generating electricity through its base electricity rates established by the Commission in general rate cases. However, though the power supply expense component embedded in base rates is static, due to the Company's unique reliance on hydro generation, actual power supply

expenses vary from year to year with changes in streamflow conditions.

4. As a result of the Company's request to establish a permanent mechanism to adjust rates annually to reflect variations in power supply costs in Case No. IPC-E-92-25, the Commission issued Order No. 24806 on March 29, 1993, in which it approved the implementation of an annual Power Cost Adjustment procedure in order to provide consistency and stability to rates.[2] The PCA is a cost recovery mechanism that passes on both the benefits and costs of supplying energy to Idaho Power customers. Neither Idaho Power nor its shareholders receive any financial return on this filing – money collected from the surcharge can be used only to pay power supply expenses.

5. Since its establishment, the PCA mechanism has been incrementally refined and modified through a series of Commission Orders, as more fully set forth below, to ensure the mechanism achieves its desired purpose and to incorporate other distinct elements, such as revenue sharing, as circumstances dictated.

6. For example, following several Commission orders addressing the need to modify the Company's then-existing PCA methodology, the Company initiated Case No. IPC-E-08-19 requesting the Commission approve a settlement stipulation that addressed a number of issues and components of the PCA. In Order No. 30715, the Commission approved the stipulation and changes to the PCA formula, which included, in pertinent part, revising the PCA sharing methodology that allocates non-PURPA[3] power supply expenses between customers and shareholders.[4] More specifically, the PCA sharing

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[2] *In the Matter of the Application of Idaho Power Company for Authority to Implement a Power Cost Adjustment Tariff for Electric Service to Customers in the State of Idaho and for Approval of New Rates for Service Under the FMC Special Contract,* Case No. IPC-E-92-25, Order No. 24806, p. 25-26 (Mar. 23, 1993).

[3] Public Utility Regulatory Policies Act of 1978 ("PURPA").

[4] *In the Matter of Idaho Power Company's Petition for Approval of Changes to its Power Cost Adjustment (PCA) Mechanism,* Case No. IPC-E-08-19, Order No. 30715, p. 4-5 (Jan. 9, 2009).

ratio was modified to 95 percent customer, 5 percent Idaho Power.[5] In addition, in Order No. 30715 the Commission approved changes to the Load Growth Adjustment Rate ("LGAR"), third-party transmission expense, the PCA forecast, and power supply expense distribution.[6]

7. Following the notice of intent to file a general rate case filed by the Company in August 2009, the Company, Commission Staff, and other stakeholders worked together to develop an approach that would allow the Company to implement a multi-year rate case moratorium while at the same time giving the Company the opportunity to recover a maintenance level of earnings over the term of the moratorium. This ultimately resulted in the Company seeking approval of a settlement stipulation filed in lieu of a general rate case in Case No. IPC-E-09-30, which was granted by the Commission in Order No. 30978.[7] Through this stipulation, a revenue sharing mechanism was established to allow the Company to amortize Accumulated Deferred Investment Tax Credits ("ADITC") when earnings fall below a certain Return on Equity ("ROE") threshold, or share a portion of revenues with Idaho customers in the form of a rate reduction when earnings are above a certain ROE threshold. This ADITC/Revenue Sharing mechanism was subsequently

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[5] With respect to PUPRA expenses and demand response incentive payments, when actual annual expenses deviate from base level NPSE, the Company is allowed to pass 100 percent of the difference for recovery or credit through the PCA.
[6] *Id.*
[7] *In the Matter of the Application of Idaho Power Company for an Accounting Order to Amortize Additional Accumulated Deferral Income Tax Credit and Approving a Rate Case Moratorium,* Case No. IPC-E-09-30, Order No. 30978, p. 5-7 (Jan. 13, 2010).

extended, and percentages, thresholds, and accounting were modified by the Commission in Order Nos. 32424,[8] 33149,[9] and 34071.[10]

8. At the Commission's request, Staff initiated Case No. GNR-E-10-03 to explore issues related to the load growth adjustment portion of the utilities' power cost adjustment mechanisms, particularly considering use of a LGAR in periods of declining load. In that case, the Commission ultimately adopted a revised LGAR methodology and changed the name of the methodology to the Load Change Adjustment Rate ("LCAR"), as set forth in Order No. 32206.[11]

9. In 2014 and 2015, the Company and Staff considered potential ways to improve the PCA's accuracy and, as a result of these efforts, agreed on a number of changes to the calculation of the PCA true-up. The ensuing proposal, to convert the PCA's existing Load Change Adjustment deferral calculation to a Sales-Based Adjustment ("SBA"), and modify the PCA deferral balance's monthly interest calculation, was set forth in a settlement agreement and submitted to the Commission in Case No. IPC-E-15-15. On May 28, 2015, the Commission issued Order No. 33307 approving changes to the PCA pursuant to the settlement agreement: (1) replacing the existing LCAR with the SBA, calculated in the same manner as the LCAR but replacing the load-based megawatt-hour ("MWh") denominator with the corresponding sales-based MWh

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[8] *In the Matter of the Application of Idaho Power Company to Extend and Modify Accounting Order to Amortize Additional Accumulated Deferred Income Tax Credits (ADITC),* Case No. IPC-E-11-22, Order No. 32424, p. 4 (Dec. 27, 2011).

[9] *In the Matter Idaho Power Company's Application to Extend its Accumulated Deferred Investment Tax Credits/Revenue Sharing Mechanism Beyond 2014,* Case No. IPC-E-14-14, Order No. 33149, p. 4-5 (Oct. 9, 2014).

[10] *In the Matter of the Investigation into the Impact of Federal Tax Code Revisions on Utility Costs and Ratemaking,* Case No. GNR-U-18-01, Order No. 34071, p. 4-5 (May 31, 2018).

[11] *In the Matter of the Commission's Inquiry into Load Growth Adjustments that Are Part of Power Cost Adjustment Mechanisms,* Case No. GNR-U-10-03, Order No. 32206, p. 6-7 (Mar. 15, 2011).

denominator; and (2) calculating monthly interest on the deferral balance by assigning annual base Net Power Supply Expenses ("NPSE") to each month according to expected base rate revenue collection as set in the Company's last general rate case, Case No. IPC-E-11-08.[12]

10. Following changes to federal and Idaho state tax rates implemented in 2018, the Commission opened a multi-utility case, Case No. GNR-U-18-01, to investigate whether to adjust utilities' rates and charges to reflect the income tax and revenue requirement reductions resulting from the tax changes. After considering the impacts of tax reform on its operations, the Company worked together with Staff on a proposal that would return to customers the tax benefits the Company was realizing under the tax law changes with limited negative impact to the Company and entered into a settlement stipulation reflecting the same. The settlement stipulation filed with the Commission on April 12, 2018, included, among other things, extending and modifying the ADITC/Revenue Sharing mechanism to the iteration applicable to the instant request.[13] On May 31, 2018, the Commission issued Order No. 34071 approving the settlement stipulation including the following modifications to the sharing portion of the mechanism, which allowed for greater customer benefits.[14] First, for actual year-end Idaho jurisdictional earnings greater than 10 percent ROE, all amounts up to and including 10.5 percent ROE will be shared between customers and the Company on an 80 percent and

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[12] *In the Matter of Idaho Power Company's Application for Approval of Computational Modifications to the True-Up Portion of the Power Cost Adjustment,* Case No. IPC-E-15-15, Order No. 33307, p. 4-5 (May 28, 2015).

[13] The mechanism was most recently modified in the Company's 2023 General Rate Case, IPC-E-23-11. However, the stipulated modifications were effective January 1, 2024, and will not impact the PCA filing until 2025.

[14] GNR-U-18-01, Order No. 34071, p. 4-5.

20 percent basis, respectively.[15] The customer revenue sharing benefit will be in the form of a reduction to rates at the time the subsequent year's PCA becomes effective. Second, Idaho earnings above a 10.5 percent ROE will also be shared, with customers receiving 55 percent of the earnings in the form of a reduction to rates at the time the subsequent year's PCA becomes effective, as well as 25 percent of the earnings applied as an offset to the Company's pension balancing account, with the Company retaining the remaining 20 percent.[16]

11. On May 28, 2021, the Commission issued Order No. 35054 approving the Company's 2021 annual PCA filing and instructing it, based on Staff's recommendation to simplify the PCA mechanism, "to initiate discussions with interested parties and to file a case with the Commission to review whether the PCA mechanism should be modified" before the Company's next PCA application.[17]

12. As a result of this endeavor, the Company proposed in Case No. IPC-E-21-38 to simplify its PCA mechanism by replacing the "true-up" and "true-up of the true-up" components of the PCA with a balancing account. On January 10, 2022, the Commission issued Order No. 35290 approving the Company's request to modify the PCA mechanism thereby combining the two true-up components into one balancing account rate, referred to below as the "Balancing Adjustment."[18] This modification was intended to make the PCA more transparent and easier to understand and does not materially affect the overall cost recovery of the PCA.

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[15] *Id.*
[16] *Id.*
[17] *In the Matter of Idaho Power Company's Application for Authority to Implement Power Cost Adjustment (PCA) Rates for Electric Service from June 1, 2021 through May 31, 2011,* IPC-E-21-10, Order No. 35054, p. 5 (May 21, 2021).
[18] *Idaho Power Company's Application for Modification of the Power Cost Adjustment Mechanism,* Case No. IPC-E-21-38, Order No. 35290, p. 2-3 (Jan. 10, 2022).

II. THE PCA MECHANISM

13. As explained more fully above, the PCA quantifies and tracks annual differences between actual NPSE and the normalized or "base level" of NPSE recovered in the Company's base rates, resulting in a credit or surcharge that is updated annually on June 1.

14. The PCA mechanism utilizes a 12-month test period of April through March ("PCA Year") and consists of a forecast component and a Balancing Adjustment (formerly referred to as the "true-up" and the "true-up of the true-up"). The PCA forecast represents the difference between the Company's NPSE forecast from its March Operating Plan and the base level NPSE recovered in the Company's base rates. The PCA sharing mechanism allows the Company to pass to Idaho customers 95 percent of the annual differences in actual non-PURPA power expenses as compared to the base level NPSE, whether positive or negative. The Balancing Adjustment includes a backward-looking tracking of differences between the prior PCA Year's forecast and actual NPSE incurred by the Company and also tracks the collection of the prior year's Balancing Adjustment.

15. The PCA is also the rate mechanism used by the Company to provide direct revenue sharing benefits resulting from the Revenue Sharing mechanism originally approved in Order No. 34071.

Forecast.

16. The Brady Testimony describes and computes the PCA rate to be effective June 1, 2024, through May 31, 2025. The system-level forecast of NPSE for the 2024-2025 PCA Year is $509,555,990, which is $24,648,746 higher than the currently approved

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base level NPSE of $484,907,244 and $31,943,394 lower than last year's forecast amount of $541,499,384. The decrease in this year's forecast is primarily due to higher forecast hydro generation compared to last year.

17. As described in Ms. Brady's testimony, the difference between the system-level forecast of NPSE and the currently approved base level NPSE is adjusted for the PCA sharing provisions and allocated to Idaho customers to determine the 2024-2025 PCA forecast component to be collected from Idaho customers of $22,712,031.

Balancing Adjustment.

18. Per Order No. 35290,[19] the "true-up" and the "true-up of the true-up" have been combined into a single Balancing Adjustment. In addition to the NPSE incurred during the April 2023 through March 2024 period, Idaho Power included its actual cost of Western Energy Imbalance Market ("EIM") participation for April 2023 through December 2023 in the Balancing Adjustment as approved by the Commission in Order No. 34100.[20] Because EIM costs were included in base rates resulting from the Company's 2023 General Rate Case, which went into effect on January 1, 2024, EIM costs are no longer included in the PCA as of that date. Benefits associated with EIM participation are embedded in actual NPSE experienced over that same period.

19. The PCA Balancing Adjustment deferral balance at the end of March 2024, with interest applied, was approximately $90 million, which represents a decrease to customers rates in this year's PCA Balancing Adjustment. Order No. 35804 in last year's PCA filing directed Idaho Power to collect the 2022-2023 PCA deferral balance equally

[19] Case No. IPC-E-21-38.

[20] *In the Matter of the Application of Idaho Power to Establish a Method of Recovery for Costs Associated with Participation in the Western Energy Imbalance Market,* Case No. IPC-E-17-16, Order No. 34100, p. 3-4 (Jul. 2, 2018).

over a two-year period. As a result, this year's balance is primarily attributed to the continued collection of last year's deferral balance. Actual power supply expenses in the 2023-2024 PCA Year were just 3 percent higher than forecast expenses, so the variance between forecast and actual power supply expenses for the 2023-2024 PCA Year had a relatively small impact on this year's deferral balance. However, this year's deferral balance does include increased benefits associated with the SBA, as well as increased Renewable Energy Credit ("REC") sales.

Revenue Sharing.

20. The Company's earnings in each year from 2011 through 2015, as well as 2018 and 2021, resulted in revenue sharing with Idaho customers totaling $126.7 million, either as a direct rate offset in the PCA or as an offset to amounts that would have otherwise been collected in rates. The Company's earnings in 2016, 2017, 2019, 2020, and 2022 were below the revenue sharing threshold. As described in greater detail in the Brady Testimony, the Company's 2023 Idaho jurisdictional year-end ROE was 9.4 percent. In accordance with the terms of the modified revenue sharing mechanism approved by the Commission in Order No. 34071,[21] the Company's Idaho jurisdictional year-end ROE was below the 10.0 percent ROE threshold for revenue sharing. Therefore, the 2024-2025 PCA will not include a revenue sharing component.

III. 2024-2025 PCA CALCULATION AND PROPOSED RATE CHANGES

PCA Rate Calculation.

21. The Brady Testimony describes in detail how the PCA rate is determined, including how each of its components are calculated. For the 2024-2025 PCA Year, the

[21] GNR-U-18-01, Order No. 34071, p. 4-5.

Company's uniform PCA is comprised of (1) the 0.1501 cents per kilowatt-hour ("kWh") for the 2024-2025 projected power cost of serving firm loads under the current PCA methodology and 95 percent sharing and (2) the 0.5946 cents per kWh for the 2023-2024 Balancing Adjustment. The sum of these two components results in a 0.7447 cents per kWh charge for all rate classes.

Cumulative Proposed June 1, 2024, Rate Changes.

22. PCA. The 2024-2025 total PCA amount, as measured from the currently approved base level NPSE is $112.7 million. This represents a decrease in total billed revenue of $35.7 million, or 2.31 percent, for Idaho customers, effective June 2024 through May 2025.

23. Fixed Cost Adjustment ("FCA"). On March 15, 2024, Idaho Power filed its annual FCA in Case No. IPC-E-24-10. The Company's 2024 FCA filing proposes a $10.6 million increase in current billed revenue, or a 1.44 percent increase, for Idaho Residential and Small General Service customers, effective June 2024 through May 2025.

24. Combined Effect of the PCA and FCA Filings. If the proposed PCA and FCA rate changes are approved as filed, the combined impact is an overall decrease in current billed revenue of $25.1 million, or 1.63 percent, for June 2024 through May 2025

25. Attachment 1 to this Application is Idaho Power's proposed IPUC No. 30, Tariff No. 101, in both clean and legislative formats, which contains the tariff sheets specifying the proposed Schedule 55 rates for providing retail electric service to its customers in the state of Idaho for June 1, 2024, through May 31, 2025.

26. Attachment 2 to this Application contains a summary of revenue impact showing the effect to each customer class of applying the Company's proposed PCA

rates that collect $35.7 million less, from June 2024 through May 2025, than the PCA rates currently in effect.

IV. COMPLIANCE WITH PRIOR COMMISSION ORDERS

IPC-E-23-12, Order No. 35804

27. In Final Order No. 35804 issued on May 31, 2023, the Commission approved the Company's request to implement PCA rates for the 2023-2024 PCA year, subject to certain conditions including (1) directing the Company to notify the Commission of any outcome of the Hells Canyon Unit No. 3 damage claim and (2) ordering Commission Staff ("Staff") to investigate the prudency of the Company's coal supply management and associated impact on NPSE. Pursuant to the Commission's direction the Company addresses each item, in turn, as follows.

28. The first issue relates to an extended outage at Hells Canyon Unit No. 3 due to repairs, and the Company's claim against the repair contractor for its failure to meet completion dates for the project. As a result of the delays, Idaho Power withheld delay liquidated damages, the majority of which were included as an offset to power supply costs in the 2023-2024 PCA Year. However, a portion was also recorded to offset labor costs that would not have otherwise occurred. The Company has provided additional detail on the delay liquidated damage amounts in Confidential Exhibit No. 5 to the Brady Testimony.

29. With respect to the Commission request for Staff to investigate the prudency of the Company's power supply expenses related to coal supply issues and report its assessment to the Commission within six months, Commission Staff filed its "Confidential Staff Report" on November 30, 2023. Based on its assessment, Staff concluded that the

Company encountered unique circumstances during the 2022-2023 year and pursued many actions to resolve the coal situation, but believed the Company could have taken additional actions to prudently mitigate NPSE. As a result, Staff recommended that an adjustment to the NPSE be considered in the Company's next PCA filing. Instead of identifying a specific adjustment, Staff recommended that the Company include Staff's Report and the Company's response with its next PCA filing to enable the Commission to make an informed decision as to any adjustments to the PCA balance. Staff's Report and the Company's response, "Analysis of Coal Supply Issues in the 2022 PCA Year", are provided as Confidential Attachment 3 and Attachment 4 to this filing, respectively. In addition, the Company has included with this filing Attachment 5 and Confidential Attachment 6, which provide supporting information and analysis. While the Company appreciates Staff's review of this matter, it does not agree that an adjustment to NPSE is reasonable under the circumstances presented. To the contrary, as more fully described in its response, the Company moved expeditiously and judiciously to mitigate the challenges that arose from sustained market volatility and limited coal inventories in the region.

V. <u>MODIFIED PROCEDURE</u>

30. Idaho Power believes that a technical hearing is not necessary to consider the issues presented herein and respectfully requests that this Application be processed under Modified Procedure, i.e., by written submissions rather than by hearing. RP 201, *et seq*. If, however, the Commission determines that a technical hearing is required, the Company stands ready to present its testimony, including but limited to the Brady

Testimony filed contemporaneously herewith, and support the Application in such hearing.

VI. COMMUNICATIONS AND SERVICE OF PLEADINGS

31. In conformance with RP 125, this Application will be brought to the attention of Idaho Power's customers by means of a press release to media in the Company's service area and a customer notice distributed in customers' bills, both of which accompany this filing. The customer notice will be distributed over the course of the Company's current billing cycles, and additionally, to ensure that all customers are notified in a timely manner and have sufficient time to submit comments, Idaho Power is sending a direct mail postcard to a subset of customers that receive their bill toward the end of the processing time for this case. As such, a bill insert and/or the direct mail postcard will be mailed no later than May 20, 2024.

32. The Company has also prominently displayed its intent to file the PCA on its website since March 15, 2024. Upon filing of this Application, this web graphic will link directly to the PCA press release and bill insert. Idaho Power will also keep its Application, testimonies, and exhibits open for public inspection at its offices throughout the state of Idaho. Idaho Power asserts that this notice procedure satisfies the Rules of Procedure of this Commission; however, the Company will, in the alternative, bring the Application to the attention of its affected customers through any other means directed by this Commission.

33. Communications and service of pleadings with reference to this Application should be sent to the following:

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VII. REQUEST FOR RELIEF

34. As discussed in greater detail above, Idaho Power respectfully requests that the Commission issue an order: (1) authorizing that this matter be processed by Modified Procedure and (2) approving an update to Schedule 55 based on the quantification of the 2024-2025 PCA, resulting in an overall decrease to current billed revenue of approximately $35.7 million to become effective June 1, 2024.

DATED at Boise, Idaho, this 15th day of April 2024.

Megan Goicoechea Allen

MEGAN GOICOECHEA ALLEN
Attorney for Idaho Power Company

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-24-17

IDAHO POWER COMPANY

ATTACHMENT NO. 1

PROPOSED SCHEDULE 55
(CLEAN AND LEGISLATIVE FORMAT)

SCHEDULE 55
POWER COST ADJUSTMENT

APPLICABILITY

This schedule is applicable to the electric energy delivered to all Idaho retail Customers served under the Company's schedules and Special Contracts listed within this schedule. These loads are referred to as "firm" load for purposes of this schedule.

BASE POWER COST AND PROJECTED POWER COST

The Base Power Cost of the Company's rates, expressed in cents per kWh, is computed by dividing the sum of the Company's power cost components by firm kWh sales. The power cost components are segmented into three categories as described in the table below:

The Projected Power Cost is the Company estimate, expressed in cents per kWh, of the power cost components for the forecasted time period beginning April 1 each year and ending the following March 31.

BALANCING ADJUSTMENT

The Balancing Adjustment is based upon the differences between previous Projected Power Cost and the power costs actually incurred. The Balancing Adjustment is 0.5946 cents per kWh.

EARNINGS SHARING

Order Nos. 30978, 32424, 33149, and 34071 directed the Company to share a portion of its earnings above a certain threshold with customers through the annual Power Cost Adjustment. The Company's 2023 earnings were not above the prescribed threshold resulting in a credit of 0.0000 cents per kWh.

SCHEDULE 55
POWER COST ADJUSTMENT
(Continued)

POWER COST ADJUSTMENT

The Power Cost Adjustment (PCA) is the sum of: 1) 95 percent of the difference between the Projected Power Costs in Category 1 and the Base Power Costs in Category 1; 2) 100 percent of the difference between the Projected Power Costs in Category 2 and the Base Power Costs in Category 2; 3) 100 percent of the difference between the Projected Power Costs in Category 3 and the Base Power Costs in Category 3; 4) the Balancing Adjustment; and 5) Earnings Sharing. The following table calculates the rates for Categories 1, 2 and 3.

The following table shows the determination of PCA rates for Categories 1, 2, and 3:

Category	Description	Base Power Cost	Projected Power Cost	Difference	Sharing %	Rate
		(¢ per kWh)				
1	The sum of fuel expense and purchased power expense (excluding purchases from cogeneration and small power producers), less the sum of off-system surplus sales revenue and revenue from market-based special contract pricing.	1.64824	1.77069	0.12245	95%	0.11633
2	Purchased power expense from cogeneration and small power producers.	1.35833	1.39092	0.03259	100%	0.03259
3	Demand response incentive payments.	0.06767	0.06881	0.00113	100%	0.00113
Total		**3.07424**	**3.23041**	**0.15617**		**0.15005**

SCHEDULE 55
POWER COST ADJUSTMENT
(Continued)

The monthly Power Cost Adjustment rates applied to the Energy rate of all metered schedules and Special Contracts are shown below. The monthly Power Cost Adjustment applied to the per unit charges of the nonmetered schedules is the monthly estimated usage times the cents per kWh rates shown below. Totals may not tie due to rounding.

Schedule	Category			Balancing Adjustment	Earnings Sharing	Total PCA
	1	2	3			
1	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
3	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
5	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
6	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
7	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
8	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
9S	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
9P	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
9T	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
15	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
19S	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
19P	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
19T	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
24	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
40	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
41	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
42	0.1163	0.0326	0.0011	0.5946	(0.0000)	0.7447
26	0.1163	0.0326	0.0011	0.5946	*	0.7447
29	0.1163	0.0326	0.0011	0.5946	*	0.7447
30	0.1163	0.0326	0.0011	0.5946	*	0.7447
32	0.1163	0.0326	0.0011	0.5946	*	0.7447
34	0.1163	0.0326	0.0011	0.5946	*	0.7447

* Earnings Sharing Credits are applied as monthly amounts per the table below.

Schedule	Special Contract	Monthly Credit
26	Micron	($0.00)
29	Simplot	($0.00)
30	DOE	($0.00)
32	Simplot-Caldwell	($0.00)
34	Lamb Weston	($0.00)

EXPIRATION

The Power Cost Adjustment included on this schedule will expire May 31, 2025.

SCHEDULE 55
POWER COST ADJUSTMENT

APPLICABILITY

This schedule is applicable to the electric energy delivered to all Idaho retail Customers served under the Company's schedules and Special Contracts listed within this schedule. These loads are referred to as "firm" load for purposes of this schedule.

BASE POWER COST AND PROJECTED POWER COST

The Base Power Cost of the Company's rates, expressed in cents per kWh, is computed by dividing the sum of the Company's power cost components by firm kWh sales. The power cost components are segmented into three categories as described in the table below:

The Projected Power Cost is the Company estimate, expressed in cents per kWh, of the power cost components for the forecasted time period beginning April 1 each year and ending the following March 31.

BALANCING ADJUSTMENT

The Balancing Adjustment is based upon the differences between previous Projected Power Cost and the power costs actually incurred. The Balancing Adjustment is 0.~~6357~~ 5946 cents per kWh.

EARNINGS SHARING

Order Nos. 30978, 32424, 33149, and 34071 directed the Company to share a portion of its earnings above a certain threshold with customers through the annual Power Cost Adjustment. The Company's 202~~2~~3 earnings were not above the prescribed threshold resulting in a credit of 0.0000 cents per kWh.

SCHEDULE 55
POWER COST ADJUSTMENT
(Continued)

POWER COST ADJUSTMENT

The Power Cost Adjustment (PCA) is the sum of: 1) 95 percent of the difference between the Projected Power Costs in Category 1 and the Base Power Costs in Category 1; 2) 100 percent of the difference between the Projected Power Costs in Category 2 and the Base Power Costs in Category 2; 3) 100 percent of the difference between the Projected Power Costs in Category 3 and the Base Power Costs in Category 3; 4) the Balancing Adjustment; and 5) Earnings Sharing. The following table calculates the rates for Categories 1, 2 and 3.

The following table shows the determination of PCA rates for Categories 1, 2, and 3:

Category	Description	Base Power Cost	Projected Power Cost	Difference	Sharing %	Rate
		(¢ per kWh)				
1	The sum of fuel expense and purchased power expense (excluding purchases from cogeneration and small power producers), less the sum of off-system surplus sales revenue and revenue from market-based special contract pricing.	~~1.661436~~1.64824	~~1.991918~~ 1.77069	~~0.330482~~0.12245	95%	~~0.313958~~0.11633
2	Purchased power expense from cogeneration and small power producers.	~~1.369206~~1.35833	~~1.395299~~ 1.39092	~~0.026093~~0.03259	100%	~~0.026093~~0.03259
3	Demand response incentive payments.	~~0.068447~~0.06767	~~0.073423~~ 0.06881	~~0.004976~~0.00113	100%	~~0.004976~~0.00113
Total		**~~3.099089~~3.07424**	**~~3.460640~~ 3.23041**	**~~0.361551~~0.15617**		**~~0.345027~~0.15005**

SCHEDULE 55
POWER COST ADJUSTMENT
(Continued)

The monthly Power Cost Adjustment rates applied to the Energy rate of all metered schedules and Special Contracts are shown below. The monthly Power Cost Adjustment applied to the per unit charges of the nonmetered schedules is the monthly estimated usage times the cents per kWh rates shown below. Totals may not tie due to rounding.

Schedule	Category			Balancing Adjustment	Earnings Sharing	Total PCA
	1	2	3			
1	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
3	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
5	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
6	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
7	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
8	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
9S	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
9P	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
9T	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
15	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
19S	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
19P	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
19T	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
24	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
40	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
41	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
42	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	(0.0000)	~~0.9807~~0.7447
26	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	*	~~0.9807~~0.7447
29	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	*	~~0.9807~~0.7447
30	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	*	~~0.9807~~0.7447
32	~~0.3140~~0.1163	~~0.0261~~0.0326	~~0.0050~~0.0011	~~0.6357~~0.5946	*	~~0.9807~~0.7447
34	0.1163	0.0326	0.0011	0.5946	*	0.7447

* Earnings Sharing Credits are applied as monthly amounts per the table below.

Schedule	Special Contract	Monthly Credit
26	Micron	($0.00)
29	Simplot	($0.00)
30	DOE	($0.00)
32	Simplot-Caldwell	($0.00)
34	Lamb Weston	($0.00)

EXPIRATION

The Power Cost Adjustment included on this schedule will expire May 31, 202~~4~~5.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-24-17

IDAHO POWER COMPANY

ATTACHMENT NO. 2

2024 REVENUE IMPACT SUMMARY

Idaho Power Company
Calculation of Revenue Impact 2024
State of Idaho
PCA
Filed April 15, 2024

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers [1]	Normalized Energy (kWh) [1]	Current Billed Revenue	Mills Per kWh	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Mills Per kWh	Percent Change Billed to Billed [2] Revenue
	Uniform Tariff Rates:									
1	Residential Service	1	502,357	5,582,403,703	$691,190,525	123.82	($13,174,473)	$678,016,052	121.46	(1.91)%
2	Master Metered Mobile Home Park	3	19	5,177,497	$613,522	118.50	($12,219)	$601,303	116.14	(1.99)%
3	Residential Service Time-of-Day	5	989	18,025,131	$2,147,357	119.13	($42,539)	$2,104,818	116.77	(1.98)%
4	Residential Service On-Site Generation	6	18,601	172,081,522	$21,541,347	125.18	($406,112)	$21,135,235	122.82	(1.89)%
5	Small General Service	7	30,614	138,530,041	$20,890,475	150.80	($326,931)	$20,563,544	148.44	(1.56)%
6	Small General Service On-Site Generation	8	107	500,088	$74,134	148.24	($1,180)	$72,954	145.88	(1.59)%
7	Large General Service	9	39,293	3,954,934,403	$360,491,542	91.15	($9,333,645)	$351,157,897	88.79	(2.59)%
8	Dusk to Dawn Lighting	15	0	2,615,028	$1,352,653	517.26	($6,171)	$1,346,481	514.90	(0.46)%
9	Large Power Service	19	124	2,067,577,655	$156,904,282	75.89	($4,879,483)	$152,024,799	73.53	(3.11)%
10	Agricultural Irrigation Service	24	19,627	1,830,563,531	$185,503,555	101.34	($4,320,130)	$181,183,425	98.98	(2.33)%
11	Unmetered General Service	40	1,700	14,381,350	$1,491,502	103.71	($33,940)	$1,457,562	101.35	(2.28)%
12	Street Lighting	41	3,324	20,670,727	$3,863,385	186.90	($48,783)	$3,814,602	184.54	(1.26)%
13	Traffic Control Lighting	42	779	2,983,484	$248,426	83.27	($7,041)	$241,385	80.91	(2.83)%
14	Total Uniform Tariffs		617,534	13,810,444,160	$1,446,312,706	104.73	($32,592,648)	$1,413,720,057	102.37	(2.25)%
15	Total Special Contracts		5	1,320,822,394	$99,344,424	75.21	($3,117,141)	$96,227,283	72.85	(3.14)%
16	**Idaho Power Supplied Retail Sales [2]**		**617,539**	**15,131,266,553**	**$1,545,657,130**	**102.15**	**($35,709,789)**	**$1,509,947,341**	**99.79**	**(2.31)%**

TY Rev Forecast - June 2024 - May 2025
(2) Percentage impact does not include Franchise Fees or Black Mesa sales

Idaho Power Company
Calculation of Revenue Impact 2024
State of Idaho
PCA
Filed April 15, 2024

Summary of Revenue Impact - Rates 9, 19, and 24 Distribution Level Detail
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers (1)	Normalized Energy (kWh) (1)	Current Billed Revenue	Mills Per kWh	Adjustments to Billed Revenue	Proposed Total Billed Revenue	Mills Per kWh	Percent Change Billed to Billed (2) Revenue
	Uniform Tariff Rates:									
1	Large General Secondary	9S	39,002	3,312,217,135	$307,142,518	92.73	($7,816,832)	$299,325,685	90.37	(2.55)%
2	Large General Primary	9P	288	638,224,106	$52,969,211	82.99	($1,506,209)	$51,463,002	80.63	(2.84)%
3	Large General Transmission	9T	3	4,493,162	$379,813	84.53	($10,604)	$369,209	82.17	(2.79)%
4	Total Schedule 9		39,293	3,954,934,403	$360,491,542	91.15	($9,333,645)	$351,157,897	88.79	(2.59)%
6	Large Power Secondary	19S	1	6,730,275	$551,693	81.97	($15,883)	$535,810	79.61	(2.88)%
7	Large Power Primary	19P	120	2,029,565,003	$154,056,978	75.91	($4,789,773)	$149,267,205	73.55	(3.11)%
8	Large Power Transmission	19T	3	31,282,377	$2,295,611	73.38	($73,826)	$2,221,784	71.02	(3.22)%
9	Total Schedule 19		124	2,067,577,655	$156,904,282	75.89	($4,879,483)	$152,024,799	73.53	(3.11)%
11	Irrigation Secondary	24S	19,627	1,830,563,531	$185,503,555	101.34	($4,320,130)	$181,183,425	98.98	(2.33)%
12	Irrigation Transmission	24T	0	0	$0	0.00	$0	$0	0.00	0.00%
13	Total Schedule 24		19,627	1,830,563,531	$185,503,555	101.34	($4,320,130)	$181,183,425	98.98	(2.33)%

TY Rev Forecast - June 2024 - May 2025
(2) Percentage impact does not include Franchise Fees or Black Mesa sales

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-24-17

IDAHO POWER COMPANY

CONFIDENTIAL

ATTACHMENT NO. 3

STAFF'S REPORT OF COAL ISSUES

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-24-17

IDAHO POWER COMPANY

ATTACHMENT NO. 4

ANALYSIS OF COAL SUPPLY ISSUES IN 2022 PCA YEAR

Analysis of Coal Supply Issues in the 2022 PCA Year

Idaho Power's Response to Staff's Confidential Report Dated November 30, 2023

April 2024

Table of Contents

Executive Summary

Background

On April 14, 2023, Idaho Power Company ("Idaho Power" or "Company") applied to the Idaho Public Utilities Commission ("Commission") in Case No. IPC-E-23-12 for authorization to implement its Power Cost Adjustment ("PCA") rates in Schedule 55—Power Cost Adjustment ("Schedule 55") effective June 1, 2023, through May 31, 2024. In Final Order No. 35804 issued on May 31, 2023, the Commission approved the Company's application, subject to certain modifications, and directed Commission Staff ("Staff") to investigate the prudency of the Company's Net Power Supply Expenses ("NPSE") related to coal supply issues and report its assessment to the Commission within six months of the Commission's final order. On November 30, 2023, Commission Staff filed its "Confidential Staff Report" in Case No. IPC-E-23-12, in which Staff concluded that the Company did not prudently incur a portion of its 2022-2023 NPSE and recommended an adjustment to NPSE be considered in the Company's next PCA filing.

While the Company appreciates Staff's review of this matter, it does not agree that an adjustment to NPSE is reasonable under the circumstances presented. To the contrary, as more fully described below, the Company moved expeditiously and judiciously to mitigate the challenges that arose from sustained market volatility and limited coal inventories in the region.

Staff's Concerns

Staff states that given the increased coal forecast and corresponding coal inventory requirements for the 2022 PCA year,[1] Idaho Power should have recognized the need to act promptly to review the Company's coal inventory, including additional procurements needed to meet the forecast, however, "Staff believes the Company did otherwise."[2] More specifically, at Bridger, Staff believes that the Company took "only minor corrective actions for the first five months of the PCA year, thereby missing the opportunity for cost-effective remedies."[3] At Valmy, on the other hand, Staff believes that the Company took reasonable actions to mitigate the shortfall, although the efforts were not successful.[4]

Based on its assessment, Staff provides two recommendations, summarized as follows, for what the Company could have done differently to have prudently mitigated NPSE. [5]

[1] In this document "2022 PCA Year" refers to the April 2022 through March 2023 time period that comprised the Balancing Adjustment portion of the PCA filed in Case No. IPC-E-23-12.
[2] Confidential Staff Report – Page 7-8
[3] Confidential Staff Report – Page 13
[4] Confidential Staff Report – Page 17
[5] Confidential Staff Report – Page 18

1. If the Company had pursued a contract with Powder River Basin (“PRB”) in March instead of September, rail service may have been available, and the Company could have had additional coal as early as June 2022.

2. If the Company had recognized in March that it could not procure the fuel needed to meet the generation requirements from the operating plan, it should have adjusted the forecast. This “would have triggered different decisions by the Company for hedging fuel or procuring long-term power contracts at more favorable prices.”

Idaho Power’s Response

Global natural gas supply and demand disruptions stemming from the Russian invasion of Ukraine resulted in unprecedented price escalation and volatility in the natural gas and energy markets beginning in the spring of 2022. This resulted in the increased economic dispatch of Idaho Power’s two coal plants – Bridger and Valmy – in the Company’s March operating plan.

In order to accommodate the increase in the economic dispatch of coal in the Company’s March operating plan, Idaho Power acted promptly to procure as much coal as possible for use in the 2022 PCA year.

Idaho Power disagrees with Staff’s assertion that it did not take enough action to procure coal for Bridger early in the PCA year. To the contrary, Idaho Power’s additional coal procurements early in the PCA year allowed the Company to run Bridger unconstrained for the entirety of the summer season. In fact, in the first few months of the PCA year, Idaho Power procured all available coal from the two suppliers in the region – there was nothing more that could have been done to secure more coal from these sources.

In addition, as system and market projections continued to indicate strong demand for coal into 2023, the Company took the more extraordinary actions of drawing from its long-term, contingency storage at Bridger and issuing a Request for Proposal (“RFP”) for coal from Powder River Basin.

It is important to note that Bridger is designed to consume coal sourced specifically from southwest Wyoming with a heat content ranging between 9,000 and 10,000 British thermal units (“Btu”) per pound. The average heat content of coal from Powder River Basin ranges between 8,500 and 9,000 Btus per pound. In addition to its negative impacts to plant efficiency, PRB coal has a high propensity to spontaneously combust and is highly friable, therefore requiring additional care in unloading and handling. As a result, PRB coal had historically been considered only as an emergency fuel option. Rather than immediately attempt to procure coal that can only be handled on a limited basis due to plant design and blending limitations, Idaho Power chose to first monitor coal generation throughout the remainder of the spring and summer to determine if acquiring this non-optimal coal supply would be necessary. Asserting that the Company should have issued an RFP immediately following the development of the

March operating plan is based on the benefit of hindsight. In actuality, it was reasonable and prudent for the Company to defer pursuing PRB coal until circumstances warranted invoking this emergency fueling option.

Ultimately, Idaho Power issued an RFP in September seeking coal from Powder River Basin to be delivered in Q4 2022. Unfortunately, securing railcars for delivery of PRB coal proved challenging. However, Staff's argument that seeking railcar sets in March rather than September would have resulted in less lead time is purely speculative; the challenges the Company confronted in September would have likely existed in March.

Lastly, Idaho Power disagrees with Staff's statement that had it updated its coal forecast in March instead of September, it would have resulted in more favorable prices for hedging activity. While Idaho Power rejects this type of analysis on the basis of hindsight, it also found the opposite to be true. Had the Company updated its forecast in March, it would have likely resulted in less favorable prices for hedging activity, resulting in increased NPSE for the PCA year.

Idaho Power provides additional detail on this analysis and its coal procurement actions throughout the 2022 PCA year in the following detailed report.

Idaho Power's Detailed Response

Bridger Operational Requirements

The Bridger plant, located near Rock Springs, Wyoming, consists of four generating units. PacifiCorp is the operator of the facility and has two-thirds ownership. Idaho Power has one-third ownership.

The plant was designed and constructed to burn sub-bituminous coal sourced from southwest Wyoming with a heat content in the range of 9,000 to 10,000 Btus per pound. The Bridger plant is adjacent to Idaho Power and PacifiCorp's co-owned Bridger Coal Company mine, which currently supplies sub-bituminous coal to the plant. Aside from BCC, the only other significant source of fuel that is within the quality specifications for Bridger is the nearby Black Butte Coal Company ("Black Butte Coal"). To supplement the Bridger plant's fueling requirements, Idaho Power and PacifiCorp have historically relied on coal procured from Black Butte Coal, jointly entering into coal supply contracts which have ranged from 3 to 4-year terms, or to 18-month to two-year terms most recently as planned exits of coal burning operations inch closer.

Relying on BCC and Black Butte Coal as the traditional fuel sources at Bridger is not merely a matter of preference. Because the physical and chemical properties of coal can vary significantly, the type and source of coal are integral components of power plant operations and cannot be substituted without careful consideration of potential impacts to plant performance, cost, and need for facility modifications and/or operational changes.

Coal from Powder River Basin has distinct properties compared to BCC and Black Butte Coal. Not only is PRB coal characterized by lower heating value due to its higher moisture content, but it is extremely friable, highly volatile, and particularly prone to spontaneous combustion. The specific attributes of PRB coal implicate issues with coal transport, handling, storage, combustion, ash deposits and other operational and maintenance matters as well as overall plant performance and costs, making it a suboptimal fueling option. Notwithstanding, Idaho Power determined that Bridger could safely and reliably use a limited amount of this particular coal each year if warranted by exigent circumstances.

Monthly Operating Plan Process

In order to consider the Company's actions relative to the issues in this case, it is important to understand how the Company develops its monthly operating plan, which provides the basis for Idaho Power's PCA forecast.

Idaho Power's monthly operating plan is developed in accordance with the Company's Energy Risk Management Standards ("ERMS"), which define a systematic methodology to manage both the physical and financial exposures to business and market-driven uncertainties within a defined and controlled framework and are intended to mitigate exposure to the volatility that can occur on a real-time basis, while retaining necessary operational flexibility. Among other things, the Company's ERMS set forth guidelines for setting volumetric and financial exposure limits that dictate the Company's allowed hedging activity, as well as the timing of when the Company can execute a hedge transaction.

In accordance with the ERMS, the Company prepares mid-term operational plans incorporating generation forecasts and associated fuel expense forecasts for its resources each month (beginning with the next month and extending at least 18 months). The procedures for developing the forecasts in accordance with the ERMS are prescriptive.

After considering any minimum "must run" operational requirements and planned unit maintenance outages, economic coal generation is modeled by comparing reported Intercontinental Exchange ("ICE") Mid-Columbia ("Mid-C") forward power prices for the upcoming months to the projected coal unit dispatch price. If the operating cost of coal is less than the forward prices, the coal units are dispatched in the plan.

Idaho Power's Risk Management Committee ("RMC") meets each month to review the operating plan, which includes any hedging transactions triggered by the market risk guidelines as defined in the ERMS. Since the inception of the ERMS, the Company has developed the operating plan based on an economic dispatch model, which includes an assumption that additional coal can be procured to meet the economic dispatch of its coal plants if needed. In addition, any hedging activity triggered from the risk guidelines was first reviewed against available coal capacity. If coal capacity was available, then it would not result in a firm hedge order.

March 2022 Operating Plan

The coal forecast prepared in mid-March 2022 and included in the operating plan presented to the Risk Management Committee ("RMC") at the March 31, 2022, RMC meeting was used to develop the 2022-2023 PCA forecast for coal-powered generation and fuel expense.

During the first part of 2022, poor hydrological conditions coupled with global natural gas supply and demand disruptions from the Russian invasion of Ukraine led to price escalation and volatility in the natural gas and energy markets. This was documented in the Company's operating plans in both February and March. More specifically, from the January to March operating plans, forward power prices had increased by 18 percent and gas prices at Sumas had increased by 24 percent. As a result, economic dispatch at Bridger and Valmy in the March 2022 operating plan was relatively high compared to prior years.

Pursuant to the ERMS framework, the Company included the higher level of economic coal generation in the March operating plan, despite coal inventory constraints, anticipating that additional coal could be obtained and that the natural gas and energy market volatility should stabilize in time, which would result in a natural (economic) reduction to coal generation in a future operating plan.

Idaho Power's Actions to Manage Coal Supply

In the face of unprecedented volatile market conditions that drove an increase in coal generation and depletion of coal stockpiles, Idaho Power undertook prudent and appropriate steps to manage coal supply and procure additional coal to mitigate the impact to customers as summarized in the following timeline and detailed in the paragraphs that follow.

TIME PERIOD	ACTION TAKEN BY IDAHO POWER	ADDITIONAL NOTES
Mar-22 Apr-22	***Bridger Coal Company*** ➢ Idaho Power increased planned deliveries from BCC for 2022 by 200,000 tons.	Idaho Power's prompt action to procure 292,333 more tons than was contemplated in the original fueling plan allowed it to run Bridger unconstrained throughout the summer season, when market prices are generally highest.
Jul-22	***Black Butte Coal*** ➢ In finalizing contract negotiations with Black Butte Coal, Idaho Power secured 92,333 more tons than was originally targeted.	
Aug-22	***Utilization of Long-Term, Contingency Coal Storage*** ➢ Idaho Power began utilizing coal inventory permitted for long-term, contingency storage at Bridger.	Inventory stockpiles ended in December 2022 and March 2023 at 8 and 6 days of full-load operating supply, respectively. These are far below historical and optimal levels, which are 30 - 45 days of supply.
Sept-22	***Actions at Bridger – Powder River Basin*** ➢ Idaho Power issued a Request for Proposal ("RFP") for additional coal from Powder River Basin.	As coal utilization continued to be higher than earlier projections, the Company pursued an emergency fueling option to incorporate PRB coal, which had never been used to fuel Bridger due to the significant care required to ship, receive, and handle the coal.
Sept-22	***Optimization of Coal Generation*** ➢ Idaho Power incorporated an optimization strategy in its operating plans after all reasonable efforts to procure additional coal had been exhausted.	The Company adjusted the dispatch price of coal for forecasting purposes and optimally dispatched available coal to meet load during periods when forward market prices were highest, therefore allocating coal to times that are most economic. This optimization strategy resulted in additional hedge transactions in the fall.

Bridger Coal Company

The primary fuel source for Bridger is the BCC mine located adjacent to the plant. Previously the mine included both surface and underground mining operations, but underground operations ceased at the end of 2021.

When coal generation stepped in as the less costly resource in 2022, Staff believes that the Company's actions did not reflect the significance of this change, noting: "When the March 2022 forecast called for 2.3 million tons of coal consumption, the Company didn't take any extraordinary actions to procure additional coal."[6] Staff further asserted that the first clear change in the Company's procurements did not occur until June.[7] These characterizations, however, are not accurate.

To the contrary, beginning in March 2022 and continuing over the ensuing months, Idaho Power quickly pivoted to address the changing circumstances and acted to procure *all available* coal from its sources. At BCC, rather than simply relying on planned operating levels of coal as Staff suggests, the Company ordered increases to planned deliveries, 133,000 tons in March and 67,000 tons in April. However, Staff incorrectly characterizes these deliveries as "essentially the amounts they intended to procure in its earlier plan." [8]

The additional 200,000 tons of coal nominated from BCC for 2022 was provided from the mine's stockpile of underground coal at BCC, which was originally earmarked for delivery to the plant through early 2024. The decision to accelerate the delivery of almost all remaining underground stockpile coal inventory at BCC was a clear change to the Company's plan and was made in the spring of 2022 when it became apparent that demand for coal at Bridger was going to exceed earlier projections.

Black Butte Coal

In addition to accelerating the delivery of coal from BCC, during the spring of 2022, the Company was in the process of negotiating a new coal supply agreement with Black Butte Coal for deliveries beginning July 2022. While the original plan called for 179,000 tons, the contract executed on June 17, 2022, was for all additional coal that Black Butte Coal could deliver to the plant for the July 2022 – December 2022 period, totaling 271,333 tons, which was 92,333 more than was originally targeted.

The record reflects that the Company's actions were commensurate with the circumstances; it secured all available coal from BCC and Black Butte Coal for use in the 2022 PCA year**,** which allowed Idaho Power to run Bridger unconstrained through the summer season. There were not additional actions that the Company could have taken, extraordinary or otherwise, to secure more coal from these sources.

[6] Confidential Staff Report – Page 12
[7] Confidential Staff Report – Page 12
[8] Confidential Staff Report – Page 12

Utilization of Long-Term, Contingency Coal Storage

In August 2022, Idaho Power began utilizing coal from the sealed emergency stockpile inventory located at the Bridger plant, drawing from coal intended for long-term, contingency storage to provide additional coal for economic dispatch. As a result, inventory stockpiles at the plant ended December 2022 and March 2023 at 8 and 6 days of full-load operating supply, respectively. These levels are far below the optimal level of 30 – 45 days of full load operating days of supply that Idaho Power has historically maintained at the plant.

Powder River Basin

By September 2022, Idaho Power had secured all available coal that could operationally and logistically be provided, yet system and market projections continued to indicate strong demand for coal generation in 2023. As a result, the Company escalated its procurement efforts, issuing an RFP to procure coal from the Powder River Basin, which was an emergency fueling option that had previously not been utilized due to its high propensity to spontaneously combust. At the same time, discussions were initiated with the railroads regarding the delivery of PRB coal and the availability of railroad owned rail sets.

Securing railcars for delivery of PRB coal proved challenging. Both Union Pacific Railway ("Union Pacific") and Burlington Northern Santa Fe ("BNSF"), the two railroad companies that haul coal out of PRB, were unable to provide service with their rail sets. As a result, PacifiCorp and Idaho Power began to explore options for leasing the required railcars.

In September and October 2022, Idaho Power and PacifiCorp discussed with NV Energy the possibility of subleasing an extra set of railcars that NV Energy was leasing but was not using at that time. However, this ultimately was not a viable option because the leasing company was in the process of selling the cars and the new owner wouldn't allow a sublease while the sale was pending.

When this fell through, Idaho Power and PacifiCorp continued to search extensively for other options, reaching out to approximately 15 different utilities and railcar leasing companies during November and December. However, no available railcar sets were identified. Finally, in January 2023, Idaho Power and PacifiCorp located and leased a railcar set from Trinity Rail LLC, which could be dispatched to PRB beginning in the March and April 2023 timeframe.

In suggesting that Idaho Power should have sought to augment coal inventory with PRB coal in March 2022,[9] Staff's report overlooks that PRB coal was considered by the Company to be an emergency fueling option to be pursued after other possibilities had been explored and exhausted. As more fully explained below, this approach was reasonable and appropriate under the circumstances. Even if the Company had pursued a contract with PRB earlier, it is entirely speculative to suggest that rail service would have been available. To the contrary, the

[9] Confidential Staff Report – Page 18

Company believes it would have been presented with the same transportation challenges and lead time associated with transporting PRB coal had it pursued that option beginning March 2022.

In addition, both Union Pacific and BNSF have been criticized over the last few years for delays and failures to meet coal shipment terms. According to an article from Wyoming Public Media, railroads have cited labor issues and weather events as reasons for the delayed or reduced service to customers.[10] In addition, an article from WyoFile from December 2022 states that 38 out of 45 utilities reported that they had to reduce coal-fired generation in 2022 due to issues with coal delivery.[11]

Implementation challenges notwithstanding, it was reasonable and prudent for the Company to defer pursuing PRB coal until September 2022, when it determined that circumstances warranted invoking this emergency fueling option. With the benefit of hindsight, one might surmise that this option should have been pursued earlier. It is important to consider, however, the factors that would have been considered by the Company at the time it was making its decisions. At that point in time, PRB coal had never been utilized at Bridger as a base fuel supply source due to its high propensity to spontaneously combust, which requires significant care be taken to ship, receive, and handle. As a result, the plant is only capable of consuming PRB on a limited scale, safely, without significant incremental investments in coal handling modifications. Because the Company had procured enough coal to run Bridger unconstrained through the summer, it waited to take the more extreme measure of procuring coal from PRB until it saw what forward market conditions were in September.

Actions at Valmy

At Valmy, Staff believes that the Company acted prudently in its efforts to secure additional coal in a timely manner. Staff notes that, "the Company showed early awareness of the coal inventory problems at Valmy and pursued reasonable and timely actions to mitigate the shortfall"[12]. Staff remained concerned, however, with what it perceived to be a lack of attention to these circumstances at the RMC, believing that "earlier recognition of the coal situation at the proper level could have led to NPSE savings by putting appropriate mitigation in place."[13] The Company is assuming that the "appropriate mitigation" that Staff is referencing is a change to the coal forecast in the March operating plan. Idaho Power addresses this point later in this report.

[10] https://www.wyomingpublicmedia.org/natural-resources-energy/2023-03-29/bnsf-has-drawn-criticism-from-a-wyoming-lawmaker-amid-a-decline-in-coal-shipments
[11] https://wyofile.com/railroad-under-fire-for-costly-decrease-in-coal-shipments/
[12] Confidential Staff Report – Page 17.
[13] Id at 6.

Optimization of Coal Generation

In late September 2022, natural gas and energy prices remained high, below normal hydro conditions persisted, and coal supply constraints continued, prompting Idaho Power to pursue resource optimization strategies to mitigate the impact . To this end, the Company adjusted the dispatch price of coal for forecasting purposes and optimally dispatched available coal to meet load during periods when forward market prices were highest, therefore allocating coal to times that are most economic.

This optimization strategy was incorporated in the Company's operating plans after all reasonable efforts to procure additional coal had been exhausted. Ultimately, it resulted in additional hedge transactions in the fall. As detailed in the meeting minutes of the September, October, and November RMC meetings, the Company continued to monitor the impact that the revised coal forecast had on the resource stack, including the resulting increase in triggered hedging activity. In addition, on October 26, 2022, Idaho Power met with Commission Staff to discuss the coal supply situation. In its presentation, the Company informed Staff on the factors that led to the limited coal supply and the Company's plan for coal dispatch going into 2023, including the recent change to the coal dispatch.

Company Analysis – Financial Impact to 2022-2023 NPSE

Staff's ultimate determination that the Company was not fully prudent is premised, in part, on its belief that if the Company recognized in March that it could not meet the coal generation requirements, it could have adjusted its forecasts accordingly. "Reduced coal generation forecasts would have raised the forecast requirements for gas generation and market purchases, which would have triggered different decisions by the Company for hedging fuel or procuring long-term power contracts at more favorable prices."[14] While retroactively deconstructing the series of events and decisions that influenced a particular outcome may be a valuable source of lessons learned, it does not provide a reasonable basis for evaluating the prudency of decisions that were made in real time without the benefit of hindsight.

Moreover, even assuming, for the sake of argument, that the Company had adjusted its March operation plan to limit coal generation, it does not necessary follow that this change would have reduced NPSE.

In order to determine the potential impact, if any, to NPSE had the Company updated its coal forecast in March instead of September, the Company performed an analysis using the methodology described in Attachment 5. The analysis itself is provided in Confidential Attachment 6. Ultimately, Idaho Power concluded that had it updated its coal forecast in March instead of September, it would have resulted in an overall **increase** to NPSE of $2.7 - $5.6 million. In other words, customers did not experience any financial harm as a result of the Company's actual course of action.

[14] Confidential Staff Report – Page 18

Conclusion

While Staff's report acknowledges the unique circumstances encountered by the Company during the 2022 PCA year, it does not adequately reflect the timing or scope of the proactive measures undertaken by the Company to address limited coal availability and turbulent market conditions. As demonstrated in this report, when Idaho Power became aware of the coal constraint issues, the Company took immediate action to procure more coal from its two suppliers, including accelerating the delivery of stockpiled coal at BCC and pursuing additional coal from Black Butte Coal. This resulted in 292,333 more tons than was contemplated in the fueling plan that was finalized in late 2021. The Company's swift actions in this regard enabled it to run Bridger at full capacity throughout the summer.

As price escalation and volatility in the gas and power markets continued to drive generation at Bridger and as coal supplies became more constrained, the Company escalated its response accordingly by drawing from coal intended for long-term, contingency storage at the Bridger plant and issuing an RFP in September 2022 to procure coal from Powder River Basin. PRB coal had not historically been used to fuel the plant and was considered an emergency option due to the additional care required to ship, receive, and handle it. Arranging for delivery of the coal presented additional challenges, which Idaho Power and PacifiCorp worked diligently to address and ultimately were able to arrange rail transport for coal in the spring of 2023. In the meantime, while working to secure transportation of PRB coal, the Company took an additional initiative to mitigate the impact of limited coal inventories, employing an optimization strategy to ensure the most cost-effective operation of the coal plants under the constrained circumstances.

The volatile market conditions in the spring of 2022 were unprecedented in recent history. The March operating plan was developed just weeks after the Russian invasion of Ukraine, and Idaho Power could not predict how the conflict would play out over the next several months. As a result, it chose to leave the forecasted economic dispatch of coal in the March operating plan and continue to monitor conditions over the next few months. As illustrated by Idaho Power's counterfactual analysis, keeping the economic dispatch of coal in the March operating plan ultimately led to lower NPSE than if the Company had updated coal dispatch levels as Staff recommended, and thus, no reasonably preventable financial harm was experienced by customers as a result of this approach.

Overall, even in hindsight, Idaho Power believes its actions to mitigate NPSE in the 2022 PCA year were swift and prudent, despite the challenges that arose from sustained market volatility and limited coal inventories in the region. Therefore, Idaho Power does not believe that any adjustment to NPSE is reasonable.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-24-17

IDAHO POWER COMPANY

ATTACHMENT NO. 5

DESCRIPTION OF COUNTERFACTUAL ANALYSIS

Counterfactual Analysis – Method

1. *Determine the additional hedge orders that would have been triggered.*

The first step of the analysis was to determine the additional firm hedge orders that would have been triggered in the March operating plan if Bridger's generation was constrained to only coal supplies that were available.

First, the Company compared the 2022 PCA coal generation forecast to the coal volume that ended up being procured for that period. A coal shortfall of approximately 775,000 tons or 1.6 million MWh was identified.

Next, the Company determined which months that coal generation would have been reduced based on forward monthly Mid-C heavy load ("HL") and light load ("LL") prices in March. Coal burn was restricted to the periods where the value of replacement energy was anticipated to be the highest.

Lastly, the Company counterfactually identified the additional HL and LL hedge orders that would have been triggered in the March operating plan. The breakdown of HL and LL additional orders by month are included in Table 1 below.

Table 1: Identified Tier 2 Firm HL and LL Hedges - MWh

	2022				**2023**
	May	June	October	November	March
HL	33,148	162,987	116,986	0	47,985
LL	0	0	123,611	161,193	78,302

2. *Determine the purchase price for the additional hedges.*

The next step of the analysis is to determine the estimated purchase price that Idaho Power would have paid for these March hedges. Because the Company could have hedged with either power or gas, it performed a counterfactual analysis for both scenarios.

For power, Idaho Power calculated the average HL and LL forward market price for each month from trade dates spanning April 8 – May 31.[1] The calculated average monthly HL and LL forward prices are provided in Table 2 below.

Table 2: Average of Daily Forward Mid-C Prices (Spring 2022)

	2022				**2023**
	May	June	October	November	March
HL	$55.36	$49.06	$83.68	$87.43	$62.82
LL	$43.38	$25.82	$75.66	$77.52	$50.78

[1] Idaho Power is assuming that the Merchant group would have realistically begun executing hedges from the March Op Plan beginning the second week in April. For the May forward month, prices from trade dates April 8 – April 29 were utilized.

For gas, Idaho Power calculated the average ICE forward price at Henry Hub, adjusted for the forecast Sumas basis, for the same trade dates. An estimated dispatch price was calculated based on Langley Gulch's average heat rate of 6,800 Btu/kWh. The calculated average monthly forward gas dispatch prices are provided in Table 3 below.

Table 3: Average of Daily Forecast Gas Dispatch Prices (Spring 2022)

2022				**2023**
May	June	October	November	March
$41.88	$51.02	$51.63	$57.53	$29.25

3. *Estimate cost actually incurred for the equivalent MWh.*

Next, Idaho Power determined the best way to estimate the actual costs incurred by the Company to procure the equivalent power or gas. For May, June, and October, the Company is assuming it would have procured the energy in the real time market. For November and March, the Company is assuming that it procured the energy via hedge transactions that were triggered in the September Op Plan.[2]

To estimate the price of power that Idaho Power would have paid in the real-time bilateral market in May, June, and October, Idaho Power calculated the average HL and LL daily index settlement price for each month. These are included in Table 4 below.

Table 4: Monthly Average Daily Index Settlement Price - Power

	May	June	October
HL	$61.87	$35.71	$72.05
LL	$48.31	$4.64	$63.04

To estimate the price of gas that Idaho Power would have paid in the real-time market in May, June, and October, Idaho Power calculated the average daily index settlement price at Sumas for each month. These are included in Table 5 below.

Table 5: Monthly Average Daily Index Settlement Price - Gas

May	June	October
$50.81	$46.90	$34.88

As stated previously, Idaho Power is assuming that it procured the equivalent November and March energy via hedge transactions executed from the September Op Plan. Therefore, to estimate the prices that the Company actually paid for the equivalent energy, it utilized forward prices from trade dates October 7th – 26th.

[2] Idaho Power began optimizing coal generation in September 2022. As a result, the September Op Plan resulted in triggers for both November and March due to the reduction of forecast coal-fired generation.

Table 6: Average of Daily Forward Mid-C Prices (Fall 2022)

	November	March
HL	$70.48	$69.50
LL	$60.03	$73.23

Table 7: Average of Daily Forecast Gas Dispatch Prices (Fall 2022)

November	March
$40.82	$36.77

4. *Calculate the estimated impact that the additional hedges would have had on NPSE.*

By comparing the forward prices in Spring 2022 to the estimated prices that Idaho Power actually paid for the equivalent MWh, Idaho Power calculated the estimated impact that hedging the additional energy in Spring 2022 would have had on NPSE for the 2022 PCA year. Ultimately, Idaho Power concluded it would have resulted in an overall increase in NPSE . This is the case for both the power and gas scenario. Table 8 below shows the estimated financial impact of the additional hedges to NPSE.

Table 8: Financial Impact of Increased Hedges to NPSE

	2022				2023	
	May	June	October	November	March	**Total**
Power	($215,948)	$2,176,385	$2,919,132	$2,820,525	($2,078,217)	**$5,621,878**
Gas	($296,059)	$671,224	$4,027,237	($2,694,778)	$948,894	**$2,656,517**

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-24-17

IDAHO POWER COMPANY

CONFIDENTIAL

ATTACHMENT NO. 6

COUNTERFACTUAL ANALYSIS