

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION)
OF IDAHO POWER COMPANY FOR)
AUTHORITY TO IMPLEMENT POWER) CASE NO. IPC-E-26-10
COST ADJUSTMENT ("PCA") RATES)
FOR ELECTRIC SERVICE FROM JUNE)
1, 2026, THROUGH MAY 31, 2027.)
_____)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JESSICA G. BRADY

1 Q. Please state your name, business address, and
2 present position with Idaho Power Company ("Idaho Power" or
3 "Company").

4 A. My name is Jessica G. Brady. My business
5 address is 1221 West Idaho Street, Boise, Idaho 83702. I am
6 employed by Idaho Power as a Regulatory Consultant in the
7 Regulatory Affairs Department.

8 Q. Please describe your educational background.

9 A. In May 2016, I received a Bachelor of Science
10 degree in Economics and a Bachelor of Arts degree in
11 Spanish from the University of Idaho. I have also attended
12 "The Basics: Practical Regulatory Training for the Electric
13 Industry," an electric utility ratemaking course offered
14 through New Mexico State University's Center for Public
15 Utilities, "Electric Utility Fundamentals & Insights," an
16 electric utility course offered through the Western Energy
17 Institute, and Edison Electric Institute's "Electric Rates
18 Course" offered at the University of Wisconsin-Madison.

19 Q. Please describe your work experience.

20 A. In September 2021, I accepted a position at
21 Idaho Power as a Regulatory Analyst in the Regulatory
22 Affairs Department. I was promoted to Senior Regulatory
23 Analyst in October 2023 and to Regulatory Consultant in
24 October 2025. As a Regulatory Consultant, I am responsible
25 for running the AURORA model ("AURORA") to calculate net

1 power supply expenses ("NPSE") for ratemaking purposes, as
2 well as the determination of the marginal cost of energy
3 used in the Company's marginal cost analyses. My duties
4 also include providing analytical support for other
5 regulatory activities within the Regulatory Affairs
6 Department.

7 Q. What is the Company requesting in this case?

8 A. The Company is requesting approval of its
9 2026-2027 Power Cost Adjustment ("PCA") rates to become
10 effective June 1, 2026. If approved, the 2026-2027 PCA
11 will result in an increase in total billed revenue of
12 approximately \$51.6 million, or 3.02 percent.

13 Q. How is your testimony organized?

14 A. My testimony consists of four sections. In the
15 first section, I provide an overview of the PCA. In the
16 second section, I detail the 2026-2027 PCA amount in
17 comparison to last year's PCA amount, identify and discuss
18 the main factors contributing to this change, which
19 includes a discussion regarding the Company's proposal to
20 return the balance of the Boardman Balancing Account, and
21 present the quantification of the 2026-2027 PCA rates to
22 become effective June 1, 2026. In the third section, I
23 discuss the additional PCA component related to revenue
24 sharing. In the fourth section, I detail the net customer
25 impact of the 2026-2027 PCA rates if approved as filed.

1 Q. Are you sponsoring any exhibits?

2 A. Yes. I am offering the following exhibits:

3 <u>Exhibit</u>	<u>Description</u>
4 Exhibit No. 1	2026-2027 PCA Forecast
5 Exhibit No. 2	2025 Balancing Adjustment
6 Exhibit No. 3	2025 ROE Determination Revenue Sharing
7 Exhibit No. 4	Confidential - Clean Energy Your Way
8	Generation and Expenses

9 **I. PCA OVERVIEW**

10 Q. What is the purpose of the PCA?

11 A. The PCA is a rate mechanism that quantifies
12 and tracks annual differences between actual NPSE and the
13 normalized or "base level" of NPSE recovered in the
14 Company's base rates, resulting in a credit or surcharge
15 that is updated annually on June 1. The PCA mechanism uses
16 a 12-month test period of April through March ("PCA Year")
17 and includes a forecast component and a Balancing
18 Adjustment. The forecast component represents the
19 difference between the Company's NPSE forecast from the
20 March Operating Plan and base level NPSE recovered in the
21 Company's base rates. The Balancing Adjustment reflects a
22 reconciliation of differences between forecast and actual
23 NPSE from the prior PCA year, including the collection of
24 the prior year's Balancing Adjustment, as well as the
25 annual variance between actual and base-level wheeling

1 revenues.

2 Q. How does the PCA mechanism function?

3 A. The PCA allows the Company to pass through to
4 customers 95 percent of the annual differences in actual
5 NPSE as compared with base level NPSE, whether positive or
6 negative, with the exception of three types of expenses.
7 For expenses associated with the Public Utility Regulatory
8 Policies Act of 1978 ("PURPA"), demand response incentive
9 payments, and capital lease payments associated with
10 battery energy storage systems ("BESS"), the Company is
11 authorized to pass 100 percent of the annual variance
12 through the PCA. The PCA is also the rate mechanism used by
13 the Company to provide customer benefits resulting from the
14 revenue sharing mechanism approved by the Commission in
15 Order No. 34071.

16 Q. Does the revenue collected from customers
17 through the annual PCA rate contribute toward the Company's
18 earnings?

19 A. No. The PCA mechanism provides for the annual
20 collection or refund of net power supply cost differences
21 between actual costs incurred by the Company and the base
22 level NPSE component of base rates. Aside from the 95
23 percent to 5 percent sharing component I just described,
24 the PCA provides for a one-for-one collection or refund of
25 actual net power supply expenses incurred, or to be

1 incurred, to provide safe, reliable electric service to
2 customers.

3 Q. What are the components of the PCA base level
4 NPSE?

5 A. The PCA base level NPSE includes the following
6 Federal Energy Regulatory Commission ("FERC") accounts:
7 Account 501, Fuel (steam); Account 536, Water for Power;
8 Account 547, Fuel (gas); Account 555, Purchased Power;
9 Account 565, Transmission of Electricity by Others; Account
10 577.4, Energy Storage Rents; and Account 447, Sales for
11 Resale (typically referred to as surplus sales).

12 The PCA base level expense component for FERC
13 Account 555 includes costs of both PURPA and non-PURPA
14 purchases. Per Order No. 32426, the Company adjusts FERC
15 Account 555 to also include demand response incentive
16 payments that the Company provides to customers who
17 participate in any of its three demand response programs.

18 **II. 2026-2027 PCA**

19 Q. What is the total PCA collection that would
20 result under the 2026-2027 PCA rates proposed by the
21 Company in this case?

22 A. The 2026-2027 PCA rates would result in total
23 PCA collection of \$86.8 million. This represents an
24 increase in total billed revenue of \$51.6 million for the
25 upcoming year, an increase of 3.02 percent.

1 Q. Have you prepared a table that details the
2 \$51.6 million revenue impact by component?

3 A. Yes. Table 1 presents a separation of the
4 \$51.6 million increase into each component included in the
5 Company's proposed rates.

Table 1 Idaho Jurisdictional Revenue Impact by Component					
Line No.	Rate Component	2025-2026 PCA	2026-2027 PCA	Difference	
1	PCA Forecast	\$ 88,931,875	\$ 165,106,470	\$ 76,174,596	
2	PCA Balancing Adjustment	\$ (53,722,317)	\$ (78,340,926) ¹	\$ (24,618,609)	
3	PCA Total	\$ 35,209,558	\$ 86,765,544	\$ 51,555,987	
4	Revenue Sharing	\$ 0	\$ 0	\$ 0	
5	Total Revenue Impact	\$ 35,209,558	\$ 86,765,544	\$ 51,555,987	

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7 Q. What are the main factors driving the revenue
8 change requested in this case?

9 A. The increase in this year's filing is driven
10 by an increase to the forecast component, partially offset
11 by a decrease to the Balancing Adjustment.

12 The increase in the forecast component is largely
13 attributable to a 16 percent decrease in forecast hydro
14 generation compared to the prior PCA year. The decrease in
15 the Balancing Adjustment is driven primarily by increased
16 Renewable Energy Credit ("REC") sales, the Sales Based
17 Adjustment ("SBA"), which reflects variances between actual
18 sales and the sales used to establish base-level NPSE, and

¹ The 2026-2027 Balancing Adjustment amount includes the Idaho-jurisdictional Boardman Balancing Account over-collection amount of \$3,279,207.

1 the inclusion of the Idaho-jurisdictional Boardman
2 Balancing Account over-collection amount of \$3,279,207²,
3 which I describe in more detail later in my testimony.

4 **A. PCA Forecast.**

5 Q. How is the PCA forecast amount determined?

6 A. As described previously, the PCA forecast
7 component represents the difference between the Company's
8 forecast of NPSE for the upcoming April - March test year
9 and base level NPSE recovered in the Company's base rates.³

10 Q. What is the Company's determination of the
11 system-level difference between currently approved base
12 level NPSE and the forecast of NPSE for the 2026-2027 PCA
13 Year?

14 A. The system-level forecast of NPSE for the
15 2026-2027 PCA Year is \$649,935,889, which is \$181,095,264
16 higher than the currently approved base level NPSE of
17 \$468,840,625. Table 2 presents the system-level differences
18 between currently approved base level NPSE and the forecast
19 of NPSE for the 2026-2027 PCA Year by FERC account.

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² Boardman Power Plant 2024 and 2025 Annual Review at Page 4, Case No. IPC-E-12-09.

³ *In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service in the State of Idaho and Authority to Implement Certain Measures to Mitigate the Impact of Regulatory Lag*, Case No. IPC-E-25-16, Order No. 36892 (December 30, 2025).

Table 2		2026 - 2027 PCA FORECAST (Total System)			
Line No.	FERC Account	Base NPSE	Forecast	Difference	
	<u>95% Sharing Accounts</u>				
1	Account 501, Steam	\$ 108,005,080	\$ 140,827,611	\$ 32,822,531	
2	Account 536, Water for Power	\$ 0	\$ 0	\$ 0	
3	Account 547, Other Fuel	\$ 50,540,155	\$ 139,451,690	\$ 88,911,536	
4	Account 555, Purchased Power Non-PURPA	\$ 124,823,345	\$ 135,649,035	\$ 10,825,690	
5	Account 565, 3rd Party Transmission	\$ 12,357,059	\$ 12,180,727	\$ (176,331)	
6	Account 447, Surplus Sales	\$ (84,493,217)	\$ (36,004,689)	\$ 48,488,528	
		\$ 211,232,422	\$ 392,104,375	\$ 180,871,953	
	<u>100% Sharing Accounts</u>				
7	Account 555, PURPA	\$ 226,719,444	\$ 225,630,980	\$ (1,088,465)	
8	Account 555, Demand Response Incentives	\$ 9,342,758	\$ 10,654,534	\$ 1,311,776	
9	Account 577.4, Energy Storage Rents	\$ 21,546,000	\$ 21,546,000	\$ 0	
10	Total	\$ 468,840,625	\$ 649,935,889	\$ 181,095,264	

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Q. What is the basis for the forecast of NPSE for the 2026-2027 PCA Year?

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A. The forecast of NPSE for the 2026-2027 PCA Year is based on the Company's March 2026 Operating Plan.

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Q. How is the NPSE forecast developed for the Company's Operating Plan?

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A. The Operating Plan is prepared monthly and represents a forecast of the Company's monthly NPSE for the following 36-month period; however, for the PCA, the Company includes only the 12 months that correspond to the PCA Year. The Operating Plan is developed using a simulation of the dispatch of the Company's generation resources for each month, with the first 12 months segmented into heavy-load and light-load hours. The

1 dispatch considers a current forecast of forward market
2 energy prices, available hydro generation, coal and natural
3 gas prices, and any existing hedge transactions. The system
4 load forecast is then analyzed against the resulting
5 monthly dispatch to determine a monthly load and resource
6 balance. Any identified resource deficiency is assumed to
7 be filled with market energy purchases or natural gas to
8 fuel either the Langley Gulch power plant ("Langley
9 Gulch"), Jim Bridger Units 1 and 2, or Valmy Units 1 and 2,
10 based on economics and available generating capacity at
11 each plant. Economically dispatched generation above the
12 system load forecast represents surplus energy sales. The
13 forecast of monthly NPSE and generation for the 2026-2027
14 PCA Year, as determined in the Company's March 2026
15 Operating Plan, is provided in Exhibit No. 1.

16 Q. How does the Company's forecast of system-
17 level NPSE for the 2026-2027 PCA compare to the system-
18 level forecast included in last year's PCA?

19 A. Table 3 below compares this year's 2026-2027
20 PCA forecast of NPSE to last year's PCA forecast by FERC
21 account. As detailed in this table, the PCA forecast on a
22 total system basis for the 2026-2027 PCA year is
23 \$649,935,889 which is \$86,372,241 higher than last year's
24 forecast amount of \$563,563,648.

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Table 3		PCA Forecast Comparison Expenses (Total System)			
Line No.	FERC Account	2025-2026 Forecast	2026-2027 Forecast	Difference	
	<u>95% Sharing Accounts</u>				
1	Account 501, Steam	\$ 151,558,050	\$ 140,827,611	\$ (10,730,438)	
2	Account 536, Water for Power	\$ 0	\$ 0	\$ 0	
3	Account 547, Other Fuel	\$ 129,974,528	\$ 139,451,690	\$ 9,477,163	
4	Account 555, Purchased Power Non-PURPA	\$ 103,402,787	\$ 135,649,035	\$ 32,246,248	
5	Account 565, 3rd Party Transmission	\$ 11,925,403	\$ 12,180,727	\$ 255,324	
6	Account 447, Surplus Sales	\$ (88,732,720)	\$ (36,004,689)	\$ 52,728,031	
		\$ 308,128,048	\$ 392,104,375	\$ 83,976,327	
	<u>100% Sharing Accounts</u>				
7	Account 555, PURPA	\$ 227,069,067	\$ 225,630,980	\$ (1,438,087)	
8	Account 555, Demand Response Incentives	\$ 10,411,533	\$ 10,654,534	\$ 243,001	
9	Account 577.4, Energy Storage Rents	\$ 17,955,000	\$ 21,546,000	\$ 3,591,000	
		\$ 255,435,600	\$ 257,831,514	\$ 2,395,914	
10	Total PCA Forecast	\$ 563,563,648	\$ 649,935,889	\$ 86,372,241	

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Q. What general conclusions can be drawn from the information contained in Table 3?

A. When viewed by category, the 95 percent sharing accounts have increased approximately \$84.0 million from last year's forecast, while the 100 percent sharing accounts have increased approximately \$2.4 million over last year's forecast.

Q. How does the Company's generation forecast for the 2026-2027 PCA compare to the forecast included in last year's PCA?

A. Table 4 below compares this year's 2026-2027 PCA generation forecast to last year's PCA forecast by FERC account. As detailed in this table, the 1,234,153 megawatt-

1 hour ("MWh") (7 percent) increase to load from the prior
 2 year is forecast to be met with a 532,193 MWh (17 percent)
 3 increase to natural gas-fired generation, a 51,674 MWh (1
 4 percent) increase to steam power generation, a 641,137 MWh
 5 (33 percent) increase to non-PURPA market purchases, and a
 6 1,281,521 MWh (89 percent) decrease to surplus sales. These
 7 are partially offset by a 1,205,849 MWh (16 percent)
 8 decrease to hydro generation and a 66,522 MWh (2 percent)
 9 decrease to PURPA generation.

Table 4		PCA Forecast Comparison Generation (Total System-MWh)		
Line No.	FERC Account	2025-2026 Forecast	2026-2027 Forecast	Difference
1	Hydro	7,440,989	6,235,140	(1,205,849)
	<u>95% Sharing Accounts</u>			
2	Account 501, Steam	3,794,723	3,846,397	51,674
3	Account 547, Other Fuel	3,067,019	3,599,211	532,193
4	Account 555, Purchased Power Non-PURPA	1,924,968	2,566,105	641,137
		16,227,698	16,246,852	19,154
	<u>100% Sharing Accounts</u>			
5	Account 555, PURPA	2,926,917	2,860,395	(66,522)
		2,926,917	2,860,395	(66,522)
6	Total Generation	19,154,615	19,107,247	(47,368)
	<u>95% Sharing Accounts</u>			
7	Less Account 447, Surplus Sales	1,447,006	165,484	(1,281,521)
8	Total Load	17,707,609	18,941,763	1,234,153

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11 Q. How are the Company's Clean Energy Your Way
 12 ("CEYW") resources accounted for in the PCA forecast?

13 A. Resources procured through the CEYW -
 14 Construction Option are paid for by the participating

1 customer. Accordingly, the cost of the PPA is not included
2 in the forecast of NPSE for the PCA year. However, the
3 participating customer will be credited for the value of
4 the resource's capacity contribution to the system and for
5 any PPA generation that exceeds their load in a given hour.
6 Both the forecast capacity credit and excess generation
7 credit amounts are included as expenses in the PCA
8 forecast.

9 Q. How are the Company's marginal-cost priced
10 customers accounted for in the PCA forecast?

11 A. All forecast marginal-cost priced energy sales
12 are included in the PCA forecast as an offset to NPSE,
13 included in FERC Account 447, Surplus Sales.

14 Q. Were any changes made to the Idaho
15 jurisdictional sales and system-level sales to account for
16 modifications related to CEYW or marginal cost-priced
17 customers?

18 A. Yes. All load forecasted to be met with CEYW
19 resources or priced at a marginal cost-based rate are
20 excluded from total forecast sales and are not used in the
21 derivation of the PCA rate.

22 Q. What is the Company's forecast of system-level
23 firm sales and Idaho jurisdictional firm sales for the
24 2026-2027 PCA Year?

1 A. For the 2026-2027 PCA Year, Idaho Power has
2 forecast system-level firm sales to be 16,727,802 MWh and
3 Idaho jurisdictional firm sales to be 16,046,892 MWh, or
4 95.93 percent of the system level.

5 Q. What is the Company's determination of the
6 2026-2027 PCA forecast component to be collected from Idaho
7 customers?

8 A. As shown in Table 1, the 2026-2027 PCA
9 forecast component to be collected from Idaho customers is
10 \$165,106,470.

11 **B. Balancing Adjustment.**

12 Q. What is this year's quantification of the
13 Balancing Adjustment, excluding amounts related to the
14 Boardman Balancing Account?

15 A. The Balancing Adjustment is detailed in the
16 PCA deferral report, attached hereto as Exhibit No. 2. This
17 report compares actual NPSE amounts to actual power cost
18 collections monthly, with the differences accumulated as a
19 deferral balance. The balance at the end of March 2026,
20 with interest applied, is negative \$75,058,413 as shown in
21 row 104 of Exhibit No. 2.

22 Q. To what factors do you attribute the
23 accumulation of the approximate negative \$75 million
24 deferral balance?

1 A. Actual power supply expenses in the 2025-2026
2 PCA Year were just 1.1 percent lower than forecast
3 expenses, with load coming in 2.6 percent lower than
4 forecast. As a result, the variance between forecast and
5 actual power supply expenses for the 2025-2026 PCA Year had
6 a relatively small impact on this year's deferral balance.
7 See Table 5 below for the variance in actual versus
8 forecast NPSE for the 2025-2026 PCA Year.

9 However, this year's deferral balance does include
10 increased benefits associated with REC sales and the SBA.

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Table 5	2025-2026 Forecast to Actual Expenses			
Line No.	FERC Account	2025-2026 Forecast	2025-2026 Actuals	Difference
<u>95% Sharing Accounts</u>				
1	Account 501, Steam	\$ 151,558,050	\$ 101,221,778	\$ (50,336,272)
2	Account 536, Water for Power	\$ 0	\$ 0	\$ 0
3	Account 547, Other Fuel	\$ 129,974,528	\$ 145,225,588	\$ 15,251,061
4	Account 555, Purchased Power Non-PURPA	\$ 103,402,787	\$ 144,262,066	\$ 40,859,279
5	Account 565, 3rd Party Transmission	\$ 11,925,403	\$ 12,101,956	\$ 176,553
6	Account 447, Surplus Sales	\$ (88,732,720)	\$ (88,216,241)	\$ 516,479
		\$ 308,128,048	\$ 314,595,148	\$ 6,467,099
<u>100% Sharing Accounts</u>				
7	Account 555, PURPA	\$ 227,069,067	\$ 215,242,160	\$ (11,826,908)
8	Account 555, Demand Response Incentives	\$ 10,411,533	\$ 8,941,045	\$ (1,470,488)
9	Account 577.4, Energy Storage Rents	\$ 17,955,000	\$ 18,707,952	\$ 752,952
		\$ 255,435,600	\$ 242,891,156	\$ (12,544,444)
9	Total	\$ 563,563,648	\$ 557,486,304	\$ (6,077,345)

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Q. Please explain the changes in actual versus forecast generation and expense for the 2025-2026 PCA Year.

A. Table 6 below details the changes in actual versus forecast generation for the 2025-2026 PCA Year.

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Table 6				
2025 - 2026 Forecast to Actual Generation				
Line No.	FERC Account	2025-2026 Forecast	2025-2026 Actuals	Difference
1	Hydro	7,440,989	6,457,120	(983,869)
	<u>95% Sharing Accounts</u>			
2	Account 501, Steam	3,794,723	2,657,274	(1,137,449)
3	Account 547, Other Fuel	3,067,019	3,686,371	619,352
4	Account 555, Purchased Power Non-PURPA	1,924,968	3,771,175	1,846,207
	95% Sharing Accounts	16,227,968	16,571,940	344,242
	<u>100% Sharing Accounts</u>			
5	Account 555, PURPA	2,926,917	2,727,746	(199,171)
	100% Accounts	2,926,917	2,727,746	(199,171)
6	Total Generation	19,154,615	19,299,687	145,072
	<u>95% Sharing Accounts</u>			
7	Account 447, Surplus Sales	1,447,006	2,057,951	610,945
8	Total Load	17,707,609	17,241,736	(465,874)

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Actual steam power generation for the 2025-2026 PCA year totaled 2,657,274 MWh, which is 30 percent lower than forecast. Actual steam fuel expense totaled \$101,221,778, which is 33 percent lower than forecast. The actual per-unit cost of steam power generation was \$38.09, a 5 percent decrease from forecast.

Actual natural gas-fired generation for the 2025-2026 PCA year totaled 3,686,371 MWh, which is 20 percent higher than forecast. Actual natural gas fuel expense totaled \$145,225,558, which is 12 percent higher than forecast. The actual per-unit cost of natural gas generation was \$39.40, a 7 percent decrease from forecast.

1 Actual non-PURPA purchased power totaled 3,771,175
2 MWh for the 2025-2026 PCA Year. This included 2,109,433 MWh
3 in market purchases and 1,661,742 MWh in PPA generation.
4 PPA generation was 0.4 percent higher than forecast,
5 whereas market purchase volumes were 680 percent higher
6 than forecast. Actual non-PURPA purchased power expense was
7 \$144,262,066, which is 40 percent higher than forecast.
8 This includes \$71,494,938 in market purchase expenses (297
9 percent higher than forecast) and \$72,767,128 in PPA
10 expenses (9 percent higher than forecast).

11 Surplus sales totaled 2,057,951 MWh for the 2025-
12 2026 PCA Year, which is 42 percent higher than forecast.
13 Actual surplus sales revenue was \$88,216,241, which is 1
14 percent lower than forecast.

15 Q. Can you elaborate on the differences between
16 forecast and actual purchases and sales?

17 A. Yes. Purchase volumes included in the PCA
18 forecast consist of the known power purchases executed in
19 accordance with the Energy Risk Managements Standards
20 ("ERMS") prior to the development of the March Operating
21 Plan. Sales volumes included in the forecast are, generally
22 speaking, based on the economics of the Company's resources
23 compared to Mid-Columbia forward market prices in the March
24 Operating Plan, and also include any known sale
25 transactions executed in accordance with the ERMS.

1 A. No. Because EIM costs were included in base
2 rates resulting from the Company's 2023 General Rate Case,
3 which went into effect on January 1, 2024, EIM costs are no
4 longer included in the PCA as of that date.

5 **C. Boardman Balancing Account Credit**

6 Q. What is the Boardman Balancing Account and why
7 was it established?

8 A. The Boardman Balancing Account was established
9 pursuant to Commission Order No. 32457 in Case No.
10 IPC-E-11-18 in connection with the planned early retirement
11 of the Boardman Power Plant. Idaho Power, as a minority
12 owner of Boardman, developed a regulatory and accounting
13 plan to respond to the plant's early closure, which
14 included establishment of a balancing account to track, on
15 a cumulative basis, both customer revenues and the actual
16 costs and credits associated with the plant's accelerated
17 depreciation, decommissioning, asset disposition, and
18 related activities. The balancing account was designed to
19 reconcile amounts collected from customers with actual
20 Boardman-related costs and credits over time.

21 Q. What Boardman-related activities have occurred
22 since the plant ceased operations, and what was the impact
23 on the balancing account?

24 A. Boardman ceased operations in October 2020,
25 with decommissioning, demolition, and site restoration

1 completed in 2023 and remaining asset disposition and
 2 closure-related transactions finalized during 2025. With all
 3 Boardman-related activities completed and recorded, the
 4 Boardman Balancing Account now reflects a final Idaho
 5 jurisdictional over-collection, as summarized below in Table
 6 7 and further described in the Company's 2024 and 2025
 7 Boardman Power Plant Annual Review Compliance Filing in
 8 Case No. IPC-E-12-09.

Table 7		
Idaho Jurisdictional Boardman Balancing Account		
Line No.		
1	Decommissioning Costs	\$ 3,108,402
2	Materials and Supplies Write-off	\$ 920,138
3	Total Decommissioning Expenditures	\$ 4,028,540
4	Collection of Costs	\$ (5,116,957)
5	Load Variance True-Up	\$ (3,950)
6	Asset Purchase Agreement Proceeds	\$ (2,186,840)
7	Under (Over) Collection	\$ (3,279,207)

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 10 Q. What is Idaho Power requesting in this case
 11 with respect to the Boardman Balancing Account?

12 A. Idaho Power proposes that the net balance of
 13 \$3,279,207 be returned to customers as a one-time giveback
 14 amortized over a 12-month period and included as a credit
 15 in this year's PCA Balancing Adjustment.

16 **D. PCA Rate Determination.**

17 Q. How is the rate for the forecast portion of
 18 the PCA for April 2026 through March 2027 determined?

1 A. The rate for the forecast portion of the PCA
2 is equal to the sum of (1) 95 percent of the difference
3 between the non-PURPA expenses quantified in the Operating
4 Plan and those quantified in the Company's last approved
5 update of NPSE, divided by the Company's forecast of system
6 firm sales for June 1, 2026, through May 31, 2027 ("System-
7 level Sales Forecast"); (2) 100 percent of the difference
8 between PURPA-related expenses quantified in the Operating
9 Plan and those quantified in the Company's last approved
10 update of NPSE, divided by the Company's System-level Sales
11 Forecast; (3) 100 percent of the difference between the
12 Idaho jurisdictional demand response incentive payments
13 quantified in the Operating Plan and those quantified in
14 the Company's last approved update of NPSE, divided by the
15 forecast of Idaho jurisdictional firm sales for June 1,
16 2026, through May 31, 2027 ("Idaho Jurisdictional Sales
17 Forecast"); and(4) 100 percent of the difference between
18 the Energy Storage Rent expenses quantified in the
19 Operating Plan and those quantified in the Company's last
20 approved update of NPSE, divided by the System-level Sales
21 Forecast.

22 Q. What is the rate for the forecast portion of
23 the PCA for April 2026 through March 2027?

24 A. The rate for non-PURPA expenses is \$0.0103 per
25 kilowatt-hour ("kWh"), which is calculated by multiplying

1 Idaho Jurisdictional Sales Forecast of 16,046,891,871 kWh,
2 results in a rate of negative \$0.0049 per kWh (-\$78,337,620
3 / 16,046,891,871 = \$0.0049/kWh.

4 Q. What is the resulting PCA rate when you
5 combine all the PCA components described previously?

6 A. The uniform PCA rate comprises (1) the \$0.0103
7 per kWh for the 2026-2027 projected power cost of serving
8 firm loads under the current PCA methodology and 95 percent
9 sharing, and (2) the negative \$0.0049 per kWh for the 2025-
10 2026 Balancing Adjustment of the PCA. The sum of these two
11 components is a \$0.0054 per kWh charge.

12 **III. ADDITIONAL PCA RATE ADJUSTMENTS**

13 **A. Revenue Sharing.**

14 Q. When was the revenue sharing mechanism
15 originally established?

16 A. The revenue sharing mechanism was originally
17 established in Case No. IPC-E-09-30 and approved in Order
18 No. 30978, effective for the years 2009-2011. Since then,
19 the revenue sharing mechanism has been modified and
20 extended five times.⁶ Order No. 34071 in Case No. GNR-U-18-
21 01 extended the revenue sharing mechanism indefinitely,
22 with modifications.

⁶ Order Nos. 32424, 33149, 34071, 36042, and 36892.

1 The mechanism was most recently modified in the
2 Company's 2025 General Rate Case, effective January 1, 2026
3 (Order No. 36892).

4 Q. What is the purpose of the Revenue Sharing
5 Mechanism?

6 A. The Revenue Sharing Mechanism includes
7 provisions for the accelerated amortization of Accumulated
8 Deferred Investment Tax Credits ("ADITC") to help achieve a
9 minimum specified percent Idaho jurisdictional return on
10 year-end equity ("Idaho ROE") and also provides for the
11 potential sharing between Idaho Power and its Idaho
12 customers of Idaho jurisdictional earnings in excess of a
13 maximum specified Idaho ROE.

14 Q. Can you explain the modifications related to
15 the Revenue Sharing Mechanism from the 2023 General Rate
16 Case?

17 A. The Revenue Sharing Mechanism was modified to
18 include an additional amount of Investment Tax Credits
19 ("ITC") equal to the incremental ITC generated from the
20 Company's investment in 2023 battery storage projects,
21 including augmentation costs. In addition, the ADITC cap
22 previously set at \$25 million was removed.

23 Effective January 1, 2024, potential revenue sharing
24 between Idaho Power and customers will occur if earnings
25 are in excess of a 9.6 percent Idaho ROE. In addition, all

1 revenue sharing will be implemented through the PCA, rather
2 than a portion offsetting customer-funded pension
3 obligations. Lastly, the minimum-specified Idaho ROE is
4 9.12 percent.⁷

5 Q. What have been the results of the revenue
6 sharing mechanism since it was implemented through 2025?

7 A. The Company's earnings in each year from 2011
8 through 2015, as well as 2018 and 2021, resulted in revenue
9 sharing with customers totaling \$126.7 million, either as a
10 direct rate offset in the PCA or as an offset to amounts
11 that would have otherwise been collected in rates. The
12 Company's earnings in 2016, 2017, 2019, 2020, and 2022-2025
13 were below the revenue sharing threshold. These amounts are
14 detailed in Table 8 below.

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⁷ *In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service in the State of Idaho and for Associated Regulatory Accounting Treatment, Case No. IPC-E-23-11, Order No. 36042 (December 28, 2023).*

Table 8		2009-2025 Revenue Sharing and ADITC (\$ Millions)					
Line No.	Revenue Sharing/ADITC Component	2009-2011	2012-2014	2015-2019	2020 - 2023	2024	2025
1	Available ADITC For Use	\$45.0	\$45.0	\$45.0	\$45.0	\$107.0	\$167.7
2	ADITC Used:	\$0.0	\$0.0	\$0.0	\$0.0	\$29.8	\$40.3
3	<u>Customer Benefits</u>						
4	Reduction to Rates:	\$27.1	\$22.8	\$8.2	\$0.6	\$0.0	\$0.0
5	Offset to Pension Balancing Account:	\$20.3	\$47.8	\$0.0	\$0.0	\$0.0	\$0.0
6	Total Sharing	\$47.4	\$70.6	\$8.2	\$0.6	\$0.0	\$0.
							Total ADITC \$70.2
							Total Sharing \$126.7

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2 Q. Did the Company's year-end 2025 financial
3 results warrant any action related to the Revenue Sharing
4 Mechanism per the terms of the 2023 Stipulation?

5 A. Yes. The Company's year-end 2025 financial
6 results yielded an actual Idaho ROE of 7.98 percent,
7 falling below the minimum specified Idaho ROE of 9.12
8 percent. As a result, \$40,336,413 of ADITC was used to
9 achieve the minimum specified ROE of 9.12 percent.

10 Q. Did the Company use the same methodology to
11 determine the Idaho jurisdictional 2025 year-end ROE that
12 was used in prior PCA filings?

13 A. Yes. The methodology used to determine the
14 Company's Idaho jurisdictional 2025 year-end ROE is
15 consistent with the methodology used for the year-end ROE
16 determinations since the inception of the mechanism.

17 Q. Do you have an exhibit demonstrating the
18 application of this methodology?

1 Q. Please summarize the Company's request in this
2 filing.

3 A. If approved, the 2026-2027 PCA will result in
4 an increase in total billed revenue of approximately \$51.6
5 million, or 3.02 percent. The Commission should approve the
6 Company's computation of the PCA rates, the calculation of
7 which follows the methodology that was approved in Order
8 No. 30715.

9 Q. Does this conclude your testimony?

10 A. Yes, it does.

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DECLARATION OF JESSICA G. BRADY

I, Jessica G. Brady, declare under penalty of perjury under the laws of the state of Idaho:


1. My name is Jessica G. Brady. I am employed by Idaho Power Company as a Regulatory Analyst in the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 1-4 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 15th day of April 2026, at Boise, Idaho.

Signed: 

Jessica Brady

**BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION
CASE NO. IPC-E-26-10**

IDAHO POWER COMPANY

**BRADY, DI
TESTIMONY**

**EXHIBIT NO. 1
PCA FORECAST**

**IDAHO POWER PCA FORECAST
APRIL 1, 2026 - MARCH 31, 2027**

Line No.	FERC Account	April	May	June	July	August	September	October	November	December	January	February	March	Annual
95% Sharing Accounts														
1	Hydroelectric Generation (MWh)	585,637	599,336	707,339	600,532	491,382	474,467	416,334	367,154	413,172	541,841	454,462	583,483	6,235,140
2	Account 536, Water for Power Total Expense	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Account 501, Steam Jim Bridger 3 & 4														
3	Energy (MWh)	31,200	32,240	31,200	148,038	239,340	231,619	239,340	231,941	239,340	239,340	216,178	239,340	2,119,115
4	Total Expense	\$ 1,073,616	\$ 1,112,446	\$ 1,077,830	\$ 5,227,748	\$ 8,505,524	\$ 8,265,924	\$ 8,570,171	\$ 8,327,245	\$ 8,614,249	\$ 8,185,225	\$ 7,166,447	\$ 7,772,363	\$ 73,898,788
Jim Bridger 1 & 2														
5	Energy (MWh)	-	-	65,869	217,049	228,826	101,229	-	115,344	205,712	94,576	63,552	18,660	1,110,816
6	Total Expense	\$ 136,701	\$ 136,701	\$ 1,037,126	\$ 6,251,640	\$ 7,058,370	\$ 2,797,026	\$ 141,807	\$ 5,701,062	\$ 12,340,350	\$ 5,776,456	\$ 3,580,527	\$ 947,266	\$ 45,905,032
Valmy														
7	Energy (MWh)	52,832	43,688	-	110,568	16,377	17,894	65,847	70,138	78,783	67,445	49,019	43,874	616,465
8	Total Expense	\$ 793,139	\$ 694,597	\$ 136,701	\$ 2,478,071	\$ 525,167	\$ 533,678	\$ 1,672,011	\$ 2,478,432	\$ 4,071,640	\$ 3,716,096	\$ 2,506,593	\$ 1,417,666	\$ 21,023,791
Account 547, Other Fuel Langley Gulch														
9	Energy (MWh)	-	140,310	207,136	210,704	211,120	208,240	62,577	201,302	226,896	227,040	202,080	219,513	2,116,918
10	Total Expense	\$ 493,883	\$ 1,971,403	\$ 3,193,751	\$ 5,410,314	\$ 5,531,909	\$ 5,229,822	\$ 1,808,302	\$ 6,966,612	\$ 10,104,206	\$ 10,185,660	\$ 8,051,083	\$ 5,831,733	\$ 64,778,679
Danskin														
11	Energy (MWh)	-	11,008	6,992	120,680	121,096	49,920	121,488	14,804	137,288	135,696	107,712	9,019	835,703
12	Total Expense	\$ 248,247	\$ 564,507	\$ 459,475	\$ 4,785,970	\$ 4,901,290	\$ 2,036,881	\$ 4,242,298	\$ 987,671	\$ 9,041,970	\$ 9,004,636	\$ 6,405,542	\$ 640,667	\$ 43,319,155
Bennett Mountain														
13	Energy (MWh)	47,424	-	-	85,320	106,536	-	78,408	132,766	79,320	77,072	39,744	-	646,590
14	Total Expense	\$ 1,139,990.02	\$ 122,270.98	\$ 122,270.98	\$ 3,307,406.98	\$ 4,198,196.82	\$ 122,270.98	\$ 2,691,333.16	\$ 6,726,265.18	\$ 5,260,475.32	\$ 5,143,439.80	\$ 2,393,665.72	\$ 126,270.52	\$ 31,353,856
Account 555, Purchased Power Non-PURPA														
15	Energy (MWh)	296,428	314,384	389,238	310,114	236,358	177,100	144,803	113,842	97,389	166,012	139,113	181,326	2,566,105
16	Total Expense	\$ 9,551,821	\$ 8,432,436	\$ 16,882,855	\$ 22,630,478	\$ 17,319,687	\$ 11,674,759	\$ 6,442,920	\$ 7,603,383	\$ 8,098,575	\$ 11,198,467	\$ 8,906,919	\$ 6,906,737	\$ 135,649,035
Account 565, 3rd Party Transmission														
17	Total Expense	\$ 779,996	\$ 718,332	\$ 967,345	\$ 1,307,772	\$ 1,189,415	\$ 976,466	\$ 1,406,345	\$ 1,011,482	\$ 908,050	\$ 1,237,473	\$ 845,430	\$ 832,621	\$ 12,180,727
Account 447, Surplus Sales														
18	Energy (MWh)	(36,313)	(13,056)	(2,268)	(2,560)	(2,260)	(1,843)	(1,568)	(1,358)	(1,332)	(36,506)	(1,531)	(64,889)	(165,484)
19	Total Expense	\$ (1,447,839)	\$ (886,411)	\$ (805,731)	\$ (1,140,382)	\$ (1,480,517)	\$ (1,829,545)	\$ (2,058,195)	\$ (3,368,292)	\$ (5,813,720)	\$ (5,554,409)	\$ (5,141,513)	\$ (6,478,135)	\$ (36,004,689)
100% Sharing Accounts														
Account 555, PURPA														
20	Energy (MWh)	282,399	309,766	290,979	275,326	264,354	224,560	209,685	174,268	182,349	187,509	216,026	243,173	2,860,395
21	Total Expense	\$ 16,578,610	\$ 18,465,700	\$ 22,474,218	\$ 25,140,277	\$ 24,679,150	\$ 17,932,305	\$ 16,507,255	\$ 16,688,984	\$ 17,679,887	\$ 15,812,056	\$ 18,361,423	\$ 15,311,115	\$ 225,630,980
Account 555, Demand Response Incentives														
22	Total Expense	\$ 19,000	\$ 39,000	\$ 309,468	\$ 3,086,657	\$ 4,676,950	\$ 1,291,208	\$ 198,487	\$ 987,764	\$ 14,000	\$ 9,000	\$ 9,000	\$ 14,000	\$ 10,654,534
Account 577.4, Energy Storage Rents														
23	Total Expense	\$ 1,795,500	\$ 1,795,500	\$ 1,795,500	\$ 1,795,500	\$ 1,795,500	\$ 1,795,500	\$ 1,795,500	\$ 1,795,500	\$ 1,795,500	\$ 1,795,500	\$ 1,795,500	\$ 1,795,500	\$ 21,546,000
<hr/>														
95% Sharing Accounts		\$ 12,769,554	\$ 12,866,283	\$ 23,071,623	\$ 50,259,018	\$ 47,749,042	\$ 29,807,281	\$ 24,916,993	\$ 36,433,860	\$ 52,625,795	\$ 48,893,044	\$ 34,714,694	\$ 17,997,189	\$ 392,104,375
100% Sharing Accounts		\$ 18,393,110	\$ 20,300,200	\$ 24,579,186	\$ 30,022,434	\$ 31,151,600	\$ 21,019,013	\$ 18,501,242	\$ 19,472,248	\$ 19,489,387	\$ 17,616,556	\$ 20,165,923	\$ 17,120,615	\$ 257,831,514
24	Total Net Power Supply Expense	\$ 31,162,665	\$ 33,166,483	\$ 47,650,809	\$ 80,281,451	\$ 78,900,642	\$ 50,826,294	\$ 43,418,235	\$ 55,906,107	\$ 72,115,182	\$ 66,509,600	\$ 54,880,617	\$ 35,117,804	\$ 649,935,889
25	Total Generation (MWh)	1,295,920	1,450,732	1,698,753	2,078,331	1,915,389	1,485,029	1,338,482	1,421,560	1,660,249	1,736,531	1,487,885	1,538,388	19,107,248
26	Total Load (MWh)	1,259,607	1,437,676	1,696,484	2,075,771	1,913,129	1,483,185	1,336,914	1,420,201	1,658,917	1,700,025	1,486,355	1,473,498	18,941,763

**BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION
CASE NO. IPC-E-26-10**

IDAHO POWER COMPANY

**BRADY, DI
TESTIMONY**

**EXHIBIT NO. 2
BALANCING ADJUSTMENT**

Power Cost Adjustment
April 2025 thru March 2026

	April	May	June	July	August	September	October	November	December	January	February	March	Totals
Idaho Jurisdiction Net Power Supply Expense (Non-QF)													
Actual Non-QF													
Fuel Expense-Steam	\$ 4,185,189.51	5,079,870.13	7,393,303.75	12,948,986.00	12,469,922.08	11,677,955.31	12,442,290.10	12,110,829.68	6,120,652.98	8,820,091.36	4,622,863.37	3,349,823.58	101,221,777.85
Fuel Expense-Gas	\$ 4,171,864.78	5,033,712.69	8,758,307.31	12,555,793.34	14,337,608.49	10,680,723.95	7,668,317.32	13,768,782.83	21,651,445.71	20,099,279.17	16,547,761.71	9,951,991.09	145,225,588.39
Non-Firm Purchases	\$ 5,024,525.17	9,140,929.96	14,361,687.80	17,976,943.09	10,895,348.01	10,675,570.30	16,084,450.58	18,695,786.80	18,807,296.43	8,388,954.11	7,089,137.09	7,121,436.81	144,262,066.15
Third Party Transmission	\$ 906,827.13	888,490.62	162,163.74	1,242,859.85	1,252,117.18	1,107,583.76	934,454.29	1,001,700.32	1,196,143.89	1,887,949.86	2,497,850.46	(976,184.90)	12,101,956.20
Surplus Sales & Transmission Losses	\$ (9,199,561.59)	(7,136,761.59)	(4,424,969.98)	(4,811,109.30)	(736,555.23)	(8,109,961.57)	(15,074,008.68)	(17,500,833.78)	(12,410,460.86)	(2,727,638.85)	(4,432,396.77)	(1,651,982.88)	(88,216,241.08)
Water for Power (Leases)	\$ -	-	-	-	-	-	-	-	-	-	-	-	-
Total Actual NPSE	\$ 5,088,845.00	13,006,241.81	26,250,492.62	39,913,472.98	38,218,440.53	26,031,871.75	22,055,503.61	28,076,265.85	35,365,078.15	36,468,635.65	26,325,215.86	17,795,083.70	314,595,147.51
Idaho Allocation	95.6%	95.9%	96.1%	97.1%	96.0%	95.9%	96.1%	95.2%	95.4%	95.6%	95.5%	96.2%	
Net Idaho Jurisdictional Actual Non-QF	\$ 4,864,935.82	12,472,985.90	25,226,723.41	38,356,847.53	36,689,702.91	24,964,565.01	21,195,338.97	26,728,605.09	33,738,284.56	34,864,015.68	25,140,581.15	17,118,870.52	301,361,456.55
Base Non-QF													
Fuel Expense-Steam	\$ 4,321,401.00	4,578,880.00	5,597,322.00	7,146,746.00	7,643,877.00	6,655,023.00	4,655,438.00	4,397,909.00	5,020,646.00	8,708,206.93	8,312,454.26	7,916,325.64	74,954,228.82
Fuel Expense-Gas	\$ 7,891,450.00	8,361,642.00	10,221,452.00	13,050,904.00	13,958,732.00	12,152,953.00	8,501,447.00	8,031,165.00	9,168,364.00	4,074,939.11	3,889,749.66	3,704,384.29	103,007,182.06
Non-Firm Purchases	\$ 6,559,959.00	6,950,818.00	8,496,830.00	10,848,881.00	11,603,535.00	10,102,437.00	7,067,034.00	6,676,100.00	7,621,425.00	11,801,431.44	11,265,104.27	10,728,267.60	109,721,822.32
Third Party Transmission	\$ 676,879.00	717,209.00	876,732.00	1,119,424.00	1,197,292.00	1,042,404.00	729,201.00	688,863.00	786,405.00	996,321.87	951,043.08	905,721.29	10,687,495.24
Surplus Sales & Transmission Losses	\$ (2,287,649.00)	(2,423,953.00)	(2,963,092.00)	(3,783,321.00)	(4,046,491.00)	(3,523,014.00)	(2,464,481.00)	(2,328,151.00)	(2,657,813.00)	(6,812,498.23)	(6,502,897.83)	(6,193,003.31)	(45,986,364.37)
Water for Power (Leases)	\$ 0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Idaho Base NPSE	\$ 17,162,040.00	18,184,596.00	22,229,244.00	28,382,634.00	30,356,945.00	26,429,803.00	18,488,639.00	17,465,886.00	19,939,027.00	18,768,401.12	17,915,453.45	17,061,695.50	252,384,364.08
Idaho Allocation	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.83%	95.83%	95.83%	
Net Idaho Jurisdiction 95% Items	\$ 16,401,761.63	17,379,018.40	21,244,488.49	27,125,283.31	29,012,132.34	25,258,962.73	17,669,592.29	16,692,147.25	19,055,728.10	17,985,758.80	17,168,379.04	16,350,222.80	241,343,475.18
Idaho Jurisdiction Change From Base													
Sharing Percentage	\$ (11,536,825.81)	(4,906,032.50)	3,982,234.92	11,231,564.22	7,677,570.57	(294,397.72)	3,525,746.68	10,036,457.84	14,682,556.46	16,878,256.88	7,972,202.11	768,647.72	60,017,981.37
Net Power Supply Expense Deferral (1)	\$ (10,959,984.52)	(4,660,730.88)	3,783,123.17	10,669,986.01	7,293,692.04	(279,677.83)	3,349,459.35	9,534,634.95	13,948,428.64	16,034,344.04	7,573,592.00	730,215.33	57,017,082.30
Idaho Jurisdictional Qualifying Facility NPSE													
Actual QF (Includes Net Metering, Raft River 100% & Liquidated Damages)													
Idaho Allocation	\$ 15,271,159.83	19,728,567.80	25,896,598.28	29,675,207.47	25,830,625.92	19,758,505.60	19,793,108.70	16,045,670.56	18,716,957.07	11,820,456.43	15,264,281.99	16,148,971.47	233,950,111.12
Idaho Jurisdictional Actual QF	\$ 14,599,228.80	18,919,696.52	24,886,630.95	28,517,874.38	24,797,400.88	18,948,406.87	19,021,177.46	15,275,478.37	17,855,977.04	11,300,356.35	14,577,389.30	15,535,310.55	224,234,927.47
Base QF													
Idaho Allocation	\$ 14,143,416.00	14,986,115.00	18,319,351.00	23,390,424.00	25,017,474.00	21,781,075.00	15,236,680.00	14,393,818.00	16,431,959.00	18,279,879.39	17,449,133.05	16,617,597.52	216,046,921.96
Idaho Jurisdictional Base	\$ 13,516,862.67	14,322,230.11	17,507,803.75	22,354,228.22	23,909,199.90	20,816,173.38	14,561,695.08	13,756,171.86	15,704,023.22	17,517,608.42	16,721,504.20	15,924,643.70	206,612,144.51
Idaho Jurisdiction Change From Base													
Sharing Percentage	\$ 1,082,366.13	4,597,466.41	7,378,827.20	6,163,646.16	888,200.98	(1,867,766.51)	4,459,482.38	1,519,306.51	2,151,953.82	(6,217,252.07)	(2,144,114.90)	(389,333.15)	17,622,782.96
QF Deferral (2)	\$ 1,082,366.13	4,597,466.41	7,378,827.20	6,163,646.16	888,200.98	(1,867,766.51)	4,459,482.38	1,519,306.51	2,151,953.82	(6,217,252.07)	(2,144,114.90)	(389,333.15)	17,622,782.96
Idaho Revenue Adjustment (SBAR)													
Actual Idaho Jurisdictional Billing Month Sales	MWh 1,041,992	1,154,889	1,398,929	1,671,616	1,671,846	1,500,405	1,180,713	1,028,839	1,118,516	1,210,052	1,244,813	1,091,459	15,314,069
Normalized Idaho Jurisdictional Billing Month Sales	MWh 1,017,495	1,092,040	1,256,135	1,544,353	1,630,099	1,445,881	1,124,956	1,049,883	1,166,688	1,311,041	1,235,222	1,183,031	15,056,824
Sales Change	MWh 24,497	62,849	142,794	127,263	41,747	54,524	55,757	(21,044)	(48,172)	(100,989)	9,591	(91,572)	257,245
% of Prior Period Billings at Old Rate-effective thru 12/31/25	\$ 30.90	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	58.605%	0.157%	0.000%	
% of Current Period Billings at New Rate-effective 01/01/26	\$ 27.82	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	41.400%	99.800%	100.000%	
Sales Adjustment Prior To Sharing @	\$ (756,959.52)	(1,942,037.56)	(4,412,343.19)	(3,932,441.41)	(1,289,992.71)	(1,684,784.77)	(1,722,880.95)	650,261.36	1,488,509.45	2,991,935.11	(266,747.00)	2,547,541.91	(8,329,939.28)
Sharing Percentage	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Idaho Revenue Adjustment (SBAR) (3)	\$ (719,111.54)	(1,844,935.68)	(4,191,726.03)	(3,735,819.34)	(1,225,493.07)	(1,600,545.53)	(1,636,736.90)	617,748.29	1,414,083.98	2,842,338.35	(253,409.65)	2,420,164.81	(7,913,442.31)
Idaho Jurisdictional Demand Response Incentive Payments													
Idaho Actual Demand Response													
Idaho Base Demand Response	\$ -	1,393.75	268,711.74	2,533,952.43	2,565,639.99	1,857,990.03	1,683,158.38	25,873.69	-	4,161.83	-	163.29	8,941,045.13
Change From Base	\$ (675,353.00)	(714,198.25)	(606,043.26)	1,417,051.43	1,371,046.99	817,936.03	955,601.38	(661,436.31)	(784,632.00)	(749,123.78)	(719,051.83)	(684,622.25)	(1,032,824.85)
Sharing Percentage	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
Change From Base (4)	\$ (675,353.00)	(714,198.25)	(606,043.26)	1,417,051.43	1,371,046.99	817,936.03	955,601.38	(661,436.31)	(784,632.00)	(749,123.78)	(719,051.83)	(684,622.25)	(1,032,824.85)
Idaho Miscellaneous Revenue													
System Emission Allowance Sales Credit	\$ -	-	-	-	-	-	-	-	-	-	-	-	-
System Renewable Energy Credit Sales	\$ 502.69	(24,886.92)	-	(9,439,816.33)	50,792.82	837.21	112.23	125.01	(17,170.11)	(24,346,168.81)	(6,267,604.26)	(8,848,382.00)	(48,891,658.47)
Revenue Subtotal	\$ 502.69	(24,886.92)	0.00	(9,439,816.33)	50,792.82	837.21	112.23	125.01	(17,170.11)	(24,346,168.81)	(6,267,604.26)	(8,848,382.00)	(48,891,658.47)
Idaho Allocation	95.6%	95.9%	96.1%	96.1%	95.9%	96.1%	96.1%	95.2%	95.4%	95.5%	95.5%	95.2%	
Sharing Percentage	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Miscellaneous Revenue Deferral (5)	\$ 456.54	(22,673.23)	0.00	(8,618,080.32)	46,323.05	762.74	102.46	113.06	(15,561.27)	(22,111,190.51)	(5,686,283.96)	(8,086,536.31)	(44,492,567.75)

Exhibit No. 2

Idaho PTP Wheeling Revenues

Case No. IPC-E-26-10

J. Brady, IPC

Page 1 of 2

Actual PTP Revenue Booked	\$	(3,717,491.44)	(3,697,939.82)	(4,224,636.74)	(4,237,448.38)	(4,296,468.51)	(4,012,888.78)	(4,265,349.50)	(4,177,519.48)	(4,502,524.42)	(4,324,917.60)	(4,040,473.68)	(4,380,435.38)	(49,878,093.73)
Idaho Allocation		95.6%	95.9%	96.1%	96.1%	96.0%	95.9%	96.1%	95.2%	95.4%	95.6%	95.5%	96.2%	
ID PTP Revenue	\$	(3,553,921.82)	(3,546,324.29)	(4,059,875.91)	(4,072,187.89)	(4,124,609.77)	(3,848,360.34)	(4,099,000.87)	(3,976,998.54)	(4,295,408.30)	(4,134,621.23)	(3,858,652.36)	(4,213,978.84)	(47,783,940.16)
% of Prior Period Billings at Old Rate-effective through 12/31/25	\$ 3.11	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	58.605%	0.157%	0.000%	
% of Current Period Billings at New Rate-effective 01/01/26	\$ 3.38	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	41.400%	99.800%	100.000%	
OATT Revenue Credited in Base Rates	\$	(3,240,595.34)	(3,591,705.14)	(4,350,670.05)	(5,198,727.24)	(5,199,442.11)	(4,666,258.86)	(3,672,016.39)	(3,199,689.11)	(3,478,585.30)	(3,898,695.61)	(4,205,129.45)	(3,689,130.91)	(48,390,645.52)
OATT Revenue Difference		(313,326.48)	45,380.85	290,794.14	1,126,539.35	1,074,832.34	817,898.52	(426,984.48)	(777,309.43)	(816,823.00)	(235,925.62)	346,477.09	(524,847.93)	606,705.36
Sharing Percentage		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
OATT Revenue Deferral (6)	\$	(297,660.15)	43,111.81	276,254.44	1,070,212.38	1,021,090.72	777,003.60	(405,635.26)	(738,443.96)	(775,981.85)	(224,129.34)	329,153.24	(498,605.53)	576,370.10
TOTAL DEFERRAL (Sum of 1-6)	\$	(11,569,286.54)	(2,601,959.82)	6,640,435.52	6,966,996.32	9,394,860.71	(2,152,287.50)	6,722,273.41	10,271,922.54	15,938,291.32	(10,425,013.31)	(900,115.10)	(6,508,717.10)	21,777,400.45

PCA Forecasted Revenues														
Actual Idaho Jurisdictional Billing Month Sales	MWh	1,041,992	1,154,889	1,398,929	1,671,616	1,671,846	1,500,405	1,180,713	1,028,839	1,118,516	1,210,052	1,244,813	1,091,459	15,314,069
% of Prior Period Billings at Old Rate		0.000%	0.000%	55.399%	0.3101%	0.000%	0.000%	0.000%	0.000%	0.000%	58.605%	0.157%	0.000%	
% of Current Period Billings at New Rate		100.000%	100.000%	44.600%	99.700%	100.000%	100.000%	100.000%	100.000%	100.000%	41.400%	99.800%	100.000%	
Forecast Rate Revenues (7)		(1,564,030.09)	(1,733,488.58)	(3,911,782.01)	(7,837,195.92)	(7,858,311.56)	(7,052,467.60)	(5,549,786.82)	(4,835,919.55)	(5,257,438.44)	(6,087,374.53)	(6,895,347.54)	(6,048,864.98)	(64,632,007.62)

PCA Balancing Account Balance														
Monthly Interest Rate 5% for 2025, 4% for 2026	%	0.4167%	0.4167%	0.4167%	0.4167%	0.4167%	0.4167%	0.4167%	0.4167%	0.4167%	0.3333%	0.3333%	0.3333%	4.7500%
Beginning Balance	\$	(52,045,993.74)	(71,591,928.94)	(83,092,625.71)	(83,618,004.78)	(79,339,339.74)	(72,538,256.58)	(76,765,014.42)	(72,222,791.17)	(63,642,103.39)	(49,480,543.82)	(62,106,657.79)	(65,936,534.19)	(52,045,993.74)
2025-2026 Incremental Deferral (Sum of 1-6 above)		(11,569,286.54)	(2,601,959.82)	6,640,435.52	6,966,996.32	9,394,860.71	(2,152,287.50)	6,722,273.41	10,271,922.54	15,938,291.32	(10,425,013.31)	(900,115.10)	(6,508,717.10)	21,777,400.45
2025-2026 PCA Forecast Revenues (Collections) 7 above		(1,564,030.09)	(1,733,488.58)	(3,911,782.01)	(7,837,195.92)	(7,858,311.56)	(7,052,467.60)	(5,549,786.82)	(4,835,919.55)	(5,257,438.44)	(6,087,374.53)	(6,895,347.54)	(6,048,864.98)	(64,632,007.62)
2025-2026 PCA Prior Balance Revenues (Collections)		(6,195,760.26)	(6,866,948.67)	(2,907,813.31)	5,497,272.99	5,595,114.59	5,280,240.00	3,689,590.89	3,445,613.09	3,745,882.12	4,051,209.02	4,172,608.43	3,655,491.66	23,162,500.55
2025-2026 Ending Balance Without Current Month Interest		(71,375,070.63)	(82,794,326.01)	(83,271,785.51)	(78,990,931.39)	(72,207,676.00)	(76,462,771.68)	(71,902,936.94)	(63,341,175.09)	(49,215,368.39)	(61,941,722.64)	(65,729,512.00)	(74,838,624.61)	(71,738,100.36)
Current Month Interest		(216,858.31)	(298,299.70)	(346,219.27)	(348,408.35)	(330,580.58)	(302,242.74)	(319,854.23)	(300,928.30)	(265,175.43)	(164,935.15)	(207,022.19)	(219,788.45)	(3,320,312.70)
2025-2026 Ending Deferral Balance	\$	(71,591,928.94)	(83,092,625.71)	(83,618,004.78)	(79,339,339.74)	(72,538,256.58)	(76,765,014.42)	(72,222,791.17)	(63,642,103.39)	(49,480,543.82)	(62,106,657.79)	(65,936,534.19)	(75,058,413.06)	(75,058,413.06)

Tab is 100% locked down, with no manual inputs.

Idaho Billed Sales	MWh	1,041,992	1,154,889	1,398,929	1,671,616	1,671,846	1,500,405	1,180,713	1,028,839	1,118,516	1,210,052	1,244,813	1,091,459	15,314,069
Oregon Billed Sales	MWh	47,806	49,780	57,526	67,705	70,248	64,187	47,932	52,146	54,307	56,256	58,744	42,982	669,619
Total	MWh	1,089,798	1,204,669	1,456,456	1,739,321	1,742,094	1,564,592	1,228,645	1,080,985	1,172,823	1,266,308	1,303,557	1,134,441	15,983,688
Idaho % Billed Sales		95.6%	95.9%	96.1%	96.1%	96.0%	95.9%	96.1%	95.2%	95.4%	95.6%	95.5%	96.2%	
Oregon % Billed Sales		4.4%	4.1%	3.9%	3.9%	4.0%	4.1%	3.9%	4.8%	4.6%	4.4%	4.5%	3.8%	

**BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION
CASE NO. IPC-E-26-10**

IDAHO POWER COMPANY

**BRADY, DI
TESTIMONY**

**EXHIBIT NO. 3
ROE DETERMINATION REVENUE SHARING**

IDAHO POWER COMPANY

ADDITIONAL INVESTMENT TAX CREDIT ANALYSIS
For the Twelve Months Ended December 31, 2025

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	Actual September 30, 2025			Actual December 31, 2025		
	TOTAL			TOTAL		
	SYSTEM	IDAHO	IDAHO %	SYSTEM	IDAHO	IDAHO %
SUMMARY OF RESULTS						
TOTAL COMBINED RATE BASE	5,298,055,015	5,065,610,359	95.6%			Sept Allocations/Ratios
DEVELOPMENT OF NET INCOME						
OPERATING REVENUES						
RETAIL SALES REVENUES (Incl 449.1 Rev)	1,233,369,462	1,181,922,554	Direct Assign	1,556,357,621	1,490,027,384	Direct Assign
OTHER OPERATING REVENUES	168,070,363	161,301,701	96.0%	247,981,706	237,994,792	96.0%
TOTAL OPERATING REVENUES	1,401,439,825	1,343,224,255		1,804,339,327	1,728,022,177	
OPERATING EXPENSES						
OPERATION & MAINTENANCE EXPENSES	895,518,946	862,906,499	96.4%	1,172,814,593	1,130,103,767	96.4%
DEPRECIATION EXPENSE	173,996,043	166,811,776	95.9%	235,023,637	225,319,551	95.9%
AMORTIZATION OF LIMITED TERM PLANT	6,649,269	6,388,251	96.1%	9,666,075	9,286,633	96.1%
TAXES OTHER THAN INCOME	21,818,127	20,145,295	92.3%	28,389,737	26,213,048	92.3%
REGULATORY DEBITS/CREDITS	4,131,455	3,878,014	93.9%	5,490,795	5,153,966	93.9%
PROVISION FOR DEFERRED INCOME TAXES	(28,931,468)	(27,509,227)	95.1%	(49,153,098)	(46,736,782)	95.1%
INVESTMENT TAX CREDIT ADJUSTMENT	10,573,330	10,121,006	95.7%	45,738,426	43,781,749	95.7%
FEDERAL INCOME TAXES	37,128,856	34,967,695	94.2%	18,645,847	17,560,527	94.2%
STATE INCOME TAXES	5,409,489	5,086,505	94.0%	3,379,772	3,177,976	94.0%
TOTAL OPERATING EXPENSES	1,126,294,048	1,082,795,814		1,469,995,784	1,413,860,434	
OPERATING INCOME	275,145,777	260,428,441		334,343,542	314,161,742	
ADD: IERCO OPERATING INCOME	1,717,822	1,646,201	95.8%	2,248,633	2,154,881	95.8%
OPERATING INCOME BEFORE OTHER INCOME AND DEDUCTIO	276,863,599	262,074,642		336,592,176	316,316,623	94.0%
ADD: AFUDC EQUITY				62,488,668	59,747,066	95.6% (L 10)
ADD: OTHER INCOME AND DEDUCTIONS				35,610,937	33,465,814	94.0% (L 33)
INCOME BEFORE INTEREST CHARGES				434,691,780	409,529,503	
LESS: INTEREST CHARGES				159,166,343	152,183,145	95.6% (L 10)
NET INCOME				275,525,437	257,346,358	
ACTUAL YEAR-END RESULTS - BEFORE ITC ADJUSTMENT						
EARNINGS ON COMMON STOCK				275,525,437	257,346,358	
COMMON EQUITY AT YEAR END				3,371,655,674	3,223,729,059	95.6% (L10)
RETURN ON YEAR-END COMMON EQUITY				8.17%	7.98%	
EARNINGS ON COMMON STOCK @ 9.12 ROE				307,494,997	294,004,090	(L44 * 9.12%)
EARNINGS ON COMMON STOCK @ 9.6 ROE				323,678,945	309,477,990	(L44 * 9.6%)
ACTUAL YEAR-END RESULTS - AFTER ITC ADJUSTMENT:						
INVESTMENT TAX CREDIT ADJUSTMENT					40,336,413	(L48-L43) / (1-9.12%)
ADJUSTED EARNINGS ON COMMON STOCK					297,682,771	
ADJUSTED COMMON EQUITY AT YEAR-END					3,264,065,472	
ADJUSTED RETURN ON YEAR-END COMMON EQUITY					9.12%	

IF IDAHO RETURN ON COMMON EQUITY (Line 46) <9.12%		
ADDITIONAL ITC ADJUSTMENT (Annualized)	If L 54 is negative, then 0 (no cap on ADITC per Order 36042)	40,336,413
IF IDAHO RETURN ON COMMON EQUITY (Line 46) >9.6%		
IDAHO EARNINGS GREATER THAN 9.6% ROE		0 (L43-L49)/(1-9.6%)
Per Order #36042:		
ROE Greater than 9.6% --CUSTOMER SHARE - 80% (Reduction to rates)	After Tax	Tax Gross Up
ROE Greater than 9.6% --COMPANY SHARE - 20%	0	-
	0	
	0	

**BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION
CASE NO. IPC-E-26-10**

IDAHO POWER COMPANY

**BRADY, DI
TESTIMONY**

**CONFIDENTIAL
EXHIBIT NO. 4
CLEAN ENERGY YOUR WAY**