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IDAHO PUBLIC
UTILITIES COMMISSION

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, 2023, THROUGH MAY 31, 2024.	CASE NO. IPC-E-23-12

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JESSICA G. BRADY

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

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

Q. Please describe your educational background.

A. In May of 2016, I received a Bachelor of Science degree in Economics and a Bachelor of Arts degree in Spanish from the University of Idaho. I have also attended "The Basics: Practical Regulatory Training for the Electric Industry," an electric utility ratemaking course offered through New Mexico State University's Center for Public Utilities and "Electric Utility Fundamentals & Insights," an electric utility course offered through the Western Energy Institute.

Q. Please describe your work experience.

A. In September 2021, I was hired as a Regulatory Analyst in Idaho Power's Regulatory Affairs Department. As a Regulatory Analyst, I provide support for the Company's regulatory activities, including compliance reporting, financial analysis, and the development of revenue forecasts for regulatory filings. I am also responsible for the Company's power cost filings in both Idaho and Oregon.

Prior to Idaho Power, I worked for five years at Clearwater Analytics, a provider of investment accounting and reporting software. I held various roles at Clearwater Analytics but was primarily focused on customer success and relationship management. I gained a breadth of knowledge in investments and the use of proprietary software to streamline the operations of a company's finance and accounting teams. I spent my last year at Clearwater developing a training program focused on providing new hires with the technical skills to be successful in an operations role.

Q. What is the Company requesting in this case?

A. The Company is requesting approval of its 2023-2024 Power Cost Adjustment ("PCA") rates to become effective June 1, 2023. If approved, the 2023-2024 PCA will result in an increase in total billed revenue of approximately $200.2 million, or 14.68 percent.

Q. How is your testimony organized?

A. My testimony consists of four sections. In the first section, I provide an overview of the PCA. In the second section, I detail the 2023-2024 PCA amount in comparison to last year's PCA amount, identify and discuss the main factors contributing to this change, and present the quantification of the 2023-2024 PCA rates to become effective June 1, 2023. In the third section, I discuss the additional PCA component related to revenue sharing. In the final section, I detail the net customer impact of the 2023-2024 PCA rates if approved as filed.

I. PCA OVERVIEW

Q. What is the purpose of the PCA?

A. The PCA is a rate mechanism that quantifies and tracks annual differences between actual Net Power Supply Expenses ("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. The PCA mechanism uses a 12-month test period of April through March ("PCA Year") and includes a forecast component and a Balancing Adjustment, formerly referred to as the "true-up" and the "true-up of the true-up". The forecast component represents the difference between the Company's NPSE forecast from the March Operating Plan and base level NPSE recovered in the Company's base rates. 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.

Q. How does the PCA mechanism function?

A. With the exception of Public Utility Regulatory Policies Act of 1978 ("PURPA") expenses and demand response incentive payments, the PCA allows the

Company to pass through to customers 95 percent of the annual differences in actual NPSE as compared with base level NPSE, whether positive or negative. With respect to PURPA expenses and demand response incentive payments, as 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. The PCA is also the rate mechanism used by the Company to provide customer benefits resulting from the revenue sharing mechanism approved by the Commission in Order No. 34071.

Q.	Does the revenue collected from customers through the annual PCA rate contribute toward the Company’s earnings?

A.	No. The PCA mechanism provides for the annual collection or refund of net power supply cost differences between actual costs incurred by the Company and the base level NPSE component of base rates. Aside from the 95 percent to 5 percent sharing component I just described, the PCA provides for a one-for-one collection or refund of actual net power supply expenses incurred, or to be incurred, to provide safe, reliable electric service to customers.

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

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

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

II. 2023-2024 PCA

Q. What is the total PCA collection that would result under the 2023-2024 PCA rates proposed by the Company in this case?

A. The 2023-2024 PCA rates would result in total PCA collection of $408.2 million. This represents an increase in total billed revenue of $200.2 million for the upcoming year, an increase of 14.68 percent.

Q. Have you prepared a table that details the $200.2 million revenue impact by component?

A. Yes. Table 1 presents a separation of the $200.2 million increase into each component included in the Company's proposed rates.

Table 1	Revenue Impact by Component			
Line No.	Rate Component	2022-2023 PCA	2023-2024 PCA	Difference
1	PCA Forecast	$ 169,966,873	$ 218,005,217	$ 48,038,344
2	PCA Balancing Adjustment	$ 38,583,273	$ 189,924,254	$ 151,625,231
3	PCA Total	$ 208,550,146	$ 408,213,721	$ 199,663,575
4	Revenue Sharing	$ (568,435)	$ 0	$ 568,435
5	**Total Revenue Impact**	**$ 207,981,710**	**$ 408,213,721**	**$ 200,232,011**

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

A. The increase in this year's PCA is driven by an increase in both the forecast component and the Balancing Adjustment. The increase in this year's forecast component is attributed primarily to higher forecast market energy and natural gas prices, combined with a limited coal supply.

As can be seen on Table 1, the Balancing Adjustment accounts for over 75 percent of the overall PCA revenue change, indicating that last year's actual power costs were greater than forecast. Similar to the forecast component, the increase in the Balancing Adjustment is largely attributed to high natural gas and market energy prices during the 2022-2023 PCA Year, combined with a limited coal supply. In addition, hydro generation was 9 percent lower than forecast.

The price increases in both the natural gas and energy markets, as well as the limited coal supply, will be discussed in more detail later in this testimony.

A. <u>PCA Forecast</u>.

Q. How is the PCA forecast amount determined?

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

Q. What is the Company's determination of the system-level difference between currently approved base level NPSE[1] and the forecast of NPSE for the 2023-2024 PCA Year?

A. The system-level forecast of NPSE for the 2023-2024 PCA Year is $541,499,384, which is $235,814,515 higher than the currently approved base level NPSE of $305,684,869. Table 2 presents the system-level differences between currently approved base level NPSE and the forecast of NPSE for the 2023-2024 PCA Year by FERC account.

[1] *In the Matter of the Application of Idaho Power Company for Authority to Establish a New Base Level of Net Power Supply Expense*, Case No. IPC-E-13-20, Order No. 33000 (March 21, 2014).

Table 2	2023 - 2024 PCA FORECAST (Total System)			
Line No.	**FERC Account**	**Base NPSE**	**Forecast**	**Difference**
	95% Sharing Accounts			
1	Account 501, Coal	$ 108,503,180	$ 130,090,026	$ 21,586,845
2	Account 536, Water for Power	$ 2,380,597	$ 0	$ (2,380,597)
3	Account 547, Other Fuel	$ 33,367,563	$ 134,492,688	$ 101,256,077
4	Account 555, Purchased Power Non-PURPA	$ 62,606,593	$ 123,485,717	$ 60,886,095
5	Account 565, 3rd Party Transmission	$ 5,455,955	$ 7,964,649	$ 2,508,694
6	Account 447, Surplus Sales	$ (51,735,153)	$ (84,191,539)	$ (32,456,386)
		$ 160,578,735	$ 311,979,464	$ 151,400,729
	100% Sharing Accounts			
7	Account 555, PURPA	$ 133,853,869	$ 218,535,412	$ 84,681,543
8	Account 555, Demand Response Incentives	$ 11,252,265	$ 10,984,508	$ (267,757)
9	Total	$ 305,684,869	$ 541,499,384	$ 235,814,515

Q. What is the basis for the forecast of NPSE for the 2023-2024 PCA Year?

A. The forecast of NPSE for the 2023-2024 PCA Year is based on the Company's March 2023 Operating Plan.

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

A. The Operating Plan is prepared monthly and represents a forecast of the Company's monthly NPSE for the following 18-month period; however, for the PCA, the Company includes only the 12 months that correspond to the PCA Year. The Operating Plan is developed by simulating the dispatch of the Company's generation resources for each month, segmented by heavy load and light load hours. The dispatch considers a current forecast of forward market energy prices, available hydro generation, coal and natural gas prices, and any existing hedge transactions. The system load forecast is then analyzed against the resulting monthly heavy load and light load dispatch to determine a monthly load and resource balance. Any identified resource deficiency is assumed to be filled with market energy purchases or natural gas to fuel the Langley Gulch power plant ("Langley Gulch"), based on economics and available generating capacity at Langley Gulch. Economically dispatched generation above the system load forecast represents surplus energy sales. The forecast of monthly NPSE and generation for the 2023-2024 PCA Year, as determined in the Company's March 2023 Operating Plan, is provided in Exhibit No. 1.

Q. Did the Company make any adjustments to the March 2023 Operating Plan, for purposes of quantifying forecast NPSE for the 2023-2024 PCA Year?

A. Yes. Forecast NPSE in the March 2023 Operating Plan includes the addition of a new power purchase agreement ("PPA"), Black Mesa Solar. For purposes of quantifying forecast NPSE for the 2023-2024 PCA Year for this filing, the Company removed the forecasted expenses associated with Black Mesa Solar, because Micron Technology, Inc. ("Micron") will be paying for 100 percent of Black Mesa Solar's generation according to the provisions of a new Energy Sales Agreement ("ESA")[2] between Idaho Power and Micron.

Q. Please provide more information on the Black Mesa Solar PPA and its treatment in the PCA forecast.

A. Black Mesa Solar is a 40 MW alternating current solar photovoltaic generation facility, expected to come online in June 2023. The PPA was negotiated in conjunction with the Micron ESA, which states that Idaho Power will procure renewable resources to assist Micron in meeting a portion of its annual energy requirements with energy generated by those resources. While the renewable resource, Black Mesa Solar in this case, will not serve Micron directly, and rather will be connected to the Company's system, Micron will pay for all of the output through its ESA.

Because Micron will be paying for 100 percent of Black Mesa Solar's generation, the cost of the PPA was removed from the Company's calculation of forecast NPSE. As recommended by Commission Staff in Order No. 35482, the Company has provided Black Mesa Solar's forecast generation and expenses, as well as Micron's monthly load forecast, as Confidential Exhibit No. 4.

[2] *In the Matter of the Replacement Special contract with Micron Technology, Inc. and Purchase Agreement with Black Mesa Energy LLC,* Case No. IPC-E-22-06, Order No. 35482 (August 01, 2022).

Q. How will the excess generation and renewable capacity credit payments, as detailed in Micron's ESA, be incorporated into this year's PCA filing?

A. In the event that Black Mesa Solar's generation exceeds Micron's load in a given hour, the Company will compensate Micron for the excess generation according to the methodology approved by the Commission in Order No. 35482. However, for the 2023-2024 PCA year, the Company does not expect Black Mesa Solar's generation to exceed Micron's load in any hour. As a result, no excess generation payments are included in this year's PCA forecast.

In addition, as stated in Order No. 35482, the Company will not begin renewable capacity credit payments until July 1, 2026. As a result, no renewable capacity credit payments are included in this year's PCA forecast.

Q. How does the Company's forecast of system-level NPSE for the 2023-2024 PCA compare to the system-level forecast included in last year's PCA?

A. Table 3 below compares this year's 2023-2024 PCA forecast of NPSE to last year's PCA forecast by FERC account. As detailed in this table, the PCA forecast on a total system basis for the 2023-2024 PCA year is $541,499,384, which is $52,004,084 higher than last year's forecast amount of $489,495,300.

Table 3	PCA Forecast Comparison Expenses (Total System)			
Line No.	FERC Account	2022-2023 Forecast	2023-2024 Forecast	Difference
	95% Sharing Accounts			
1	Account 501, Coal	$ 151,179,160	$ 130,090,026	$ (21,089,135)
2	Account 536, Water for Power	$ 0	$ 0	$ 0
3	Account 547, Other Fuel	$ 79,067,982	$ 134,623,640	$ 55,555,657
4	Account 555, Purchased Power Non-PURPA	$ 98,482,808	$ 123,492,688	$ 25,009,880
5	Account 565, 3rd Party Transmission	$ 5,149,239	$ 7,964,649	$ 2,815,409
6	Account 447, Surplus Sales	$ (65,085,848)	$ (84,191,539)	$ (19,105,691)
		$ 268,793,342	$ 311,979,464	$ 43,186,122
	100% Sharing Accounts			
7	Account 555, PURPA	$ 212,586,058	$ 218,535,412	$ 5,949,354
8	Account 555, Demand Response Incentives	$ 8,115,900	$ 10,984,508	$ 2,868,608
		$ 220,701,958	$ 229,519,920	$ 8,817,962
9	Total PCA Forecast	$ 489,495,300	$ 541,499,384	$ 52,004,084

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 $43.2 million from last year’s forecast, while the 100 percent sharing accounts have increased approximately $8.8 million over last year’s forecast.

Q. What factors are contributing to the major differences presented in Table 3?

A. Forecast expenses included in the 95 percent sharing accounts are expected to increase by 16 percent as compared to last year, from $268,793,342 to $311,979,464. Due to the limited coal supply, the Company expects to rely more on natural gas generation and purchased power to serve load in the 2023-2024 PCA Year.

Q. Please explain the circumstances that led to the Company’s limited coal supply.

A. Global natural gas supply and demand disruptions over the last several months, stemming from the Russian invasion of Ukraine and sabotage of the Nord Stream pipelines, have caused price escalation and volatility in the natural gas and energy markets.

As the same time, the U.S. has been ramping down its coal production, limiting the supply of coal available to the electric utility sector. Similarly, production capabilities at Bridger Coal Company (“BCC”) have decreased as a result of the closing of the underground mining operations at the end of 2021.

As a result of the price escalation and volatility in the natural gas and energy markets throughout 2022, Idaho Power increased its reliance on coal-fired generation to serve load. Actual coal-fired generation for the first 9 months of 2022 was 50 percent higher than the same period in 2021, and 30 percent higher than the 5-year average for the period.

The increase in coal-fired generation in 2022, combined with the closure of the underground mine at BCC, has resulted in a limited supply of coal available for use in 2023. Coal availability is expected to improve in 2024, however, when Bridger Units 1 and 2 are converted to natural gas fired units, thus reducing Idaho Power's coal-fired fleet from 5 units to 3 units.

Q. How is Idaho Power working to limit the customer impact of the current coal constraints at the Bridger plant?

A. Idaho Power plans to use 100 percent of the available production capacity from BCC through 2023. Idaho Power is actively working with its operating partner at BCC, PacifiCorp, to identify opportunities to maximize coal production with existing infrastructure, resources, and equipment.

In addition to utilizing 100 percent of available production capacity at BCC, the Company has secured all available coal from its primary third-party supplier, Black Butte Coal Company, through 2023.

Idaho Power has also recently secured rail transportation that will allow for approximately 200,000 tons of spot coal to be delivered from the Powder River Basin ("PRB") to the Bridger plant beginning in May 2023 through December 2023. While PRB coal has not been utilized at Bridger as a base fuel supply source to date due to its high propensity to spontaneously combust, the plant is capable of consuming PRB coal on a limited scale. Idaho

Power intends to rely on as much PRB coal as can be delivered and burned safely at the plant in 2023.

Q. Has the Company and its partner considered increasing the capacity to produce coal at BCC?

A. Yes. However, no feasible, cost-effective methods of increasing coal production capacity in the short term have been identified. Increasing coal production at BCC to levels that would completely fill the shortfall in supply would require new permits and additional investment in capital infrastructure. Because the current coal supply constraints are not expected to persist after the conversion of Bridger Units 1 and 2 to natural gas, additional investment to fill the near-term temporary shortfall in coal supply would not provide a benefit to customers in the long-term.

Q. What is Idaho Power doing to address coal constraints at the Valmy plant?

A. At Valmy, Idaho Power is actively working to secure additional coal supply for 2023, 2024, and 2025. Solicitations made in a June 2022 Request for Proposal ("RFP") seeking 2023 coal volumes from spot coal suppliers indicated minimal Western coal available and higher coal prices.

As a result of the knowledge gained from the June 2022 RFP, Idaho Power, and its co-owner of Valmy, NV

Energy, commissioned an independent engineering firm to evaluate the performance capabilities of the current dry sorbent injection system and feasibility of installing activated carbon injection systems that would enhance controls to allow Valmy to burn higher mercury and sulfur coals. Based on information provided by the engineering firm, Valmy plant specifications for mercury and sulfur were refined.

In November 2022, NV Energy and Idaho Power issued a new RFP seeking coal for 2023. Idaho Power has scheduled a test burn for a new fuel source from this RFP, and a contract is being negotiated with the supplier pending finalization of rail transportation. Idaho Power expects that this volume of additional coal, combined with existing stockpile inventory, will provide fuel to operate Valmy during the summer months of 2023, as well as the winter months of 2023–24.

Q. Please elaborate on the changes in the 95 percent sharing accounts for this year's forecast as compared with last year's forecast as presented in Table 3.

A. For the 2023-2024 PCA year, the average forecast market purchase price is $76.01 per megawatt-hour ("MWh"), compared to $49.11 per MWh last year, an increase of 55 percent. In addition, the per-unit cost of natural gas for the 2023-2024 PCA year is $41.27 per MWh, an increase of 33 percent compared to last year. As a result of the limited coal supply, the per-unit cost of coal generation has also increased from last year. The average per-unit cost of coal-fired generation for the 2023-2024 PCA year is $36.95 per MWh, an increase of 24 percent compared to last year. Accordingly, expenses from non-PURPA purchased power are expected to increase 25 percent as compared to last year's forecast, natural gas expense is expected to increase 70 percent, and coal fuel expense is expected to decrease 14 percent.

The increase in forecast market energy prices is also resulting in higher surplus sales revenue. Surplus sales revenue is expected to increase 29 percent compared to last year, from $65,085,848 to $84,191,539. For the 2023-2024 PCA Year, the average forecast market sales price is $82.96 per MWh compared with $51.73 last year, a 60 percent increase.

Q. What factors are contributing to the change in the 100 percent sharing accounts?

A. As can be seen in Table 3, forecast expenses included in the 100 percent sharing accounts are expected to increase by 4 percent as compared to last year, from $220,701,958 to $229,519,920. Forecast PURPA costs increased by $5.95 million as compared to last year's forecast and forecast demand response incentive payments increased by $2.9 million as compared to last year.

Q. Is the increase in forecast PURPA costs related to increased generation output from PURPA projects?

A. In part. Table 4 details changes between last year's PCA forecast and this year's PCA forecast with respect to forecasted generation in MWh. As shown in Table 4, PURPA generation is anticipated to increase by 19,189 MWh, or less than 1 percent. The 3 percent increase in PURPA expense is largely the result of price escalation in PURPA contracts, for which the average cost is $71.47 per MWh, compared to $69.96 last year.

Table 4	**PCA Forecast Comparison Generation (Total System-MWh)**			
Line No.	**FERC Account**	**2022-2023 Forecast**	**2023-2024 Forecast**	**Difference**
1	Hydro	5,972,743	6,487,995	515,252
	<u>95% Sharing Accounts</u>			
2	Account 501, Coal	5,083,043	3,520,905	(1,562,138)
3	Account 547, Other Fuel	2,556,322	3,261,784	705,462
4	Account 555, Purchased Power Non-PURPA	1,580,326	1,695,683	115,357
	95% Sharing Accounts	15,192,435	14,966,367	(226,068)
	<u>100% Sharing Accounts</u>			
5	Account 555, PURPA	3,038,613	3,057,802	19,189
	100% Accounts	3,038,613	3,057,802	19,189
6	Total Generation	18,231,048	18,024,169	(206,879)
	<u>95% Sharing Accounts</u>			
7	Account 447, Surplus Sales	1,258,195	1,014,817	(243,978)
8	Total Load	16,972,853	17,009,352	36,499

Q. What other general conclusions can be drawn from the information in Table 4?

A. Compared to last year's forecast, hydro generation is expected to increase from 5,972,743 MWh to 6,487,995 MWh, or 9 percent. Due to the limited coal supply, coal-fired generation is expected to decrease from 5,083,043 MWh to 3,520,905 MWh, or 31 percent. To offset the reduction in coal-fired generation, natural gas generation is expected to increase 28 percent compared to last year. In addition, non-PURPA purchased power is expected to increase 7 percent from last year. This 7 percent increase is due to an increase in PPA generation, more specifically, the increased forecast generation from Jackpot Solar, which came online in December 2022.

Q. What is causing the 9 percent increase in expected hydro generation?

A. The increase in expected hydro generation is mainly due to higher projected inflows into Brownlee reservoir. The March Operating Plan used in this year's PCA forecast projects April through July inflows into Brownlee of 4.3 million acre-feet ("MAF") as compared to 2.9 MAF used to determine last year's PCA forecast, an increase of 69 percent. Expected inflows into Brownlee are higher than last year's PCA forecast as a result of better snowpack conditions, which provide for sustained runoff and increased hydro generation during the spring and summer months. Snowpack conditions used to determine this year's PCA hydro forecast are 117 percent of normal, compared to 76 percent of normal last year.

Q. How are the forecasted NPSE differences presented in Table 2 used to determine the 2023-2024 PCA forecast component to be collected from Idaho customers?

A. The 2023-2024 PCA forecast component reflects the Idaho jurisdictional share of the forecasted NPSE differences presented in Table 2, adjusted for the PCA sharing provisions. The Idaho jurisdictional share of the forecast NPSE differences is determined by applying a ratio of forecast firm Idaho jurisdictional sales to forecast firm system-level sales to the system-level NPSE differences.

Q. Were any changes made to the Idaho jurisdictional sales and system-level sales to account for the portion of Micron's load met by Black Mesa Solar?

A. Yes. The portion of Micron's load forecast to be met by Black Mesa Solar was removed from the total forecast Idaho jurisdictional sales and system-level sales and was not used in the derivation of the PCA rate.

Q. What is the Company's forecast of system-level firm sales and Idaho jurisdictional firm sales, net of the portion of Micron's load met by Black Mesa Solar, for the 2023-2024 PCA Year?

A. For the 2023-2024 PCA Year, Idaho Power has forecast system-level firm sales to be 15,684,447 MWh and Idaho jurisdictional firm sales to be 14,982,736 MWh, or 95.52 percent of the system level.

Q. What is the Company's determination of the 2023-2024 PCA forecast component to be collected from Idaho customers?

A. The 2023-2024 PCA forecast component to be collected from Idaho customers is $218,006,526. Table 5 presents the determination of the 2023-2024 PCA forecast component by individual PCA expense and revenue category.

Table 5	2023-2024 PCA FORECAST			
Line No.	**FERC Account**	**Difference from Base**	**Difference After Sharing**	**Idaho Allocation**
	95% Sharing Accounts	(From Table 1)		
1	Account 501, Coal	$ 21,586,845	$ 20,507,503	$ 19,588,713
2	Account 536, Water for Power	$ (2,380,597)	$ (2,261,567)	$ (2,160,243)
3	Account 547, Other Fuel	$ 101,256,077	$ 96,193,273	$ 91,883,560
4	Account 555, Purchased Power Non-PURPA	$ 60,886,095	$ 57,841,790	$ 55,250,325
5	Account 565, 3rd Party Transmission	$ 2,508,694	$ 2,383,259	$ 2,276,483
6	Account 447, Surplus Sales	$ (32,456,386)	$ (30,833,566)	$ (29,452,141)
		$ 151,400,729	$ 143,830,692	$ 137,386,697
	100% Sharing Accounts			
7	Account 555, PURPA	$ 84,681,543	$ 84,681,543	$ 80,887,586
8	Account 555, Demand Response Incentives	$ (267,757)	$ (267,757)	$ (267,757)
9	Total	$ 235,814,515	$ 228,244,478	$ 218,006,526

B. Balancing Adjustment.

Q. What is this year's quantification of the Balancing Adjustment?

A. The Balancing Adjustment is detailed in the PCA deferral report, attached hereto as Exhibit No. 2. This report compares actual NPSE amounts to actual power cost collections monthly, with the differences accumulated as a deferral balance. The balance at the end of March 2023, with interest applied, was $190,205,569 as shown on row 100 of Exhibit No. 2. The approximate $190 million represents an increase to customer rates in this year's PCA Balancing Adjustment.

Q. To what factors do you attribute the accumulation of the approximate $190 million deferral balance?

A. The approximate $190 million deferral balance was primarily driven by a decrease in actual hydro generation from expected as well as higher than forecast market purchases and natural gas generation, due to a limited coal supply.

Actual hydro generation for the 2022-2023 PCA year totaled 5,458,343 MWh, a 9 percent decrease from last year's forecast of 5,972,743 MWh. Actual purchased power totaled 4,297,723 MWh, a 172 percent increase from last year's forecast. Actual natural gas generation totaled

2,716,835 MWh, a 6 percent increase from last year’s forecast. Lastly, actual surplus sales volumes totaled 1,455,119 MWh, an increase of 16 percent from last year.

Actual natural gas and market energy prices were also higher than forecast, driving a 126 percent increase in natural gas fuel expense and a 318 percent increase in purchased power expense.

In addition, due to the limited coal supply, the Company began optimizing its coal-fired generation dispatch in October 2022. At a high level, this dispatch optimization process involved reducing coal unit dispatch during lower market price conditions to ensure the plants were available to operate during high load and/or high market price conditions. As a result, actual coal-fired generation totaled 3,265,218 MWh, a decrease of 36 percent compared to last year’s forecast.

Q. Please elaborate on the changes in actual versus forecast generation and expense for the 2022-2023 PCA Year.

A. Last year’s PCA forecast included an average market sales price of $51.73 per MWh. The actual average market sales price for the 2022-2023 PCA year was $116.98 per MWh, a 126 percent increase. As a result of the difference in forecast and actual market sales prices, as well as economic opportunity during the spring and winter months of the 2022-2023 PCA year, actual surplus sales volumes were 16 percent higher than forecast. Surplus sales revenue totaled $170,224,982, which was 162 percent higher than forecast revenues of $65,085,848.

As mentioned above, actual coal-fired generation for the 2022-2023 PCA year was 36 percent lower than forecast. Actual coal fuel expense totaled $94,955,998, which was 37 percent lower than forecast. Coal-fired generation was lower than forecast due to the limited coal supply, as discussed earlier in testimony.

Natural gas generation totaled 2,716,835 MWh for the 2022-2023 PCA Year, which was 6 percent higher than forecast. Due to the increased natural gas prices, actual natural gas expense totaled $178,317,313, which was 126 percent higher than forecast. While natural gas prices were higher than forecast, the Company’s reliance on natural gas generation increased 6 percent as it was needed to meet load, as well as make off-system sales when it was economic, as noted previously.

While both purchased power and surplus sales increased, surplus sale volumes were highest in off-peak spring and winter months, and purchased power was highest in summer months, where hot temperatures caused continuously higher than forecast peak loads.

Q. Were there any items included in this year's Balancing Adjustment in addition to actual NPSE incurred during the April 2022 through March 2023 period?

A. Yes. Per Commission Order No. 34100, Idaho Power included its actual costs of Western Energy Imbalance Market ("EIM") participation for April 2022 through March 2023 in the Balancing Adjustment. Benefits associated with EIM participation are embedded in actual NPSE experienced over that same period.

Q. Please summarize the conditions of Order No. 34100 as they pertain to EIM cost recovery through the 2022 PCA.

A. Per the terms of the settlement stipulation ("EIM Stipulation") approved by Order No. 34100, Idaho Power agreed to include an EIM-related monthly revenue requirement in its monthly PCA deferral calculation based on actual EIM participation costs commencing April 1, 2018. The Company also agreed to apply a soft cap to EIM-related revenue requirement included in the PCA deferral equal to annual EIM benefits as reported by the California Independent System Operator ("CAISO") for the corresponding period.

Q. Is the EIM-related revenue requirement included in the April 2022 through March 2023 PCA deferral under the soft cap of annual CAISO-reported benefits for that same period?

A. Yes. For the April 2022 through March 2023 period, the EIM-related revenue requirement totaled $2.5 million, while CAISO reported EIM benefits for Idaho Power of approximately $37.7 million from April through December (CAISO's first quarter 2023 report has not yet been published). Therefore, the Company's EIM-related revenue requirement is less than the soft cap agreed to in the EIM Stipulation.

Q. Does Idaho Power believe the EIM has provided net benefits to customers since joining in April 2018?

A. Yes. While Idaho Power believes the CAISO benefit calculation overstates estimated benefits to Idaho Power's system, the Company believes customers have realized significant net benefits since the Company's entry into the EIM in April 2018. As discussed in the Company's May 24, 2019, Report of EIM Benefits and Costs of Participation, filed in Case No. IPC-E-16-19, Idaho Power has developed a more precise methodology for determining EIM benefits that uses inputs specific to the Company. Based on this methodology, the Company believes benefits achieved between April 2022 and December 2022 are approximately $9 million (benefits for the first quarter of 2023 are not yet available). This level of EIM benefits compared to the Idaho-jurisdictional EIM costs of $2.5 million, demonstrates a net benefit to the Company and, ultimately, its customers.

C. PCA Rate Determination.

Q. How is the rate for the forecast portion of the PCA for April 2023 through March 2024 determined?

A. The rate for the forecast portion of the PCA is equal to the sum of (1) 95 percent of the difference between the non-PURPA expenses quantified in the Operating Plan and those quantified in the Company's last approved update of NPSE, divided by the Company's forecast of system firm sales for June 1, 2023, through May 31, 2024[3] ("System-level Sales Forecast"); and (2) 100 percent of the difference between PURPA-related expenses quantified in the Operating Plan and those quantified in the Company's last approved update of NPSE, divided by the Company's System-level Sales Forecast; and (3) 100 percent of the difference between the Idaho jurisdictional demand response incentive payments quantified in the Operating Plan and those quantified in the Company's last approved update of NPSE, divided by the forecast of Idaho jurisdictional firm sales[4] for June 1, 2023, through May 31, 2024.

[3] System-level and Idaho jurisdictional firm sales used in the calculation are net of Black Mesa Solar's forecasted generation for the June 2023 – May 2024 time period.
[4] *Id.*

Q. What is the rate for the forecast portion of the PCA for April 2023 through March 2024?

A. The rate for non-PURPA expenses is 0.9183 cents per kilowatt-hour (“kWh”), which is calculated by multiplying $151,400,729 from Table 2 by 95 percent and then dividing it by the System-level Sales Forecast, net of Black Mesa Solar generation, of 15,662,267 MWh (($151,400,729 * 0.95) / 15,662,267) = $9.183 /MWh = 0.9183 cents/kWh). The rate for PURPA expenses is 0.5407 cents per kWh, which is calculated by dividing $84,681,543 from Table 2 by the 15,662,267 MWh ($84,681,543 / 15,662,267 MWh = $5.407/MWh = 0.5407 cents/kWh). The rate for demand response incentive payments is negative 0.0018 cents per kWh, which is calculated by dividing the negative $267,757 from Table 2 by the forecast of Idaho jurisdictional firm sales, net of Black Mesa Solar generation, of 14,960,556 MWh (-$267,757 / 14,960,556 MWh = -$0.0180/MWh = -0.0018 cents/kWh). The forecast portion of the PCA rate is 1.4572 cents per kWh, which is calculated by adding the non-PURPA expense of 0.9183 cents per kWh to the PURPA expense of 0.5407 cents per kWh to the demand response incentive payment of negative 0.0018 cents per kWh (0.9183 + 0. 5407 + -0.0018 = 1.4572 cents/kWh).

Q. How did you compute this year’s Balancing Account rate?

A. As shown in Exhibit No. 2, this year's Balancing Adjustment of the PCA is approximately $190 million, which, when divided by the Company's forecast of Idaho jurisdictional sales, net of Black Mesa generation, of 14,960,556 MWh, results in a rate of 1.2714 cents per kWh ($190,205,569 / 14,960,556 = $12.714/MWh = 1.2714 cents/kWh).

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

A. The uniform PCA rate comprises (1) the 1.4572 cents per kWh for the 2023-2024 projected power cost of serving firm loads under the current PCA methodology and 95 percent sharing, and (2) the 1.2714 cents per kWh for the 2022-2023 Balancing Adjustment of the PCA. The sum of these two components is a 2.7286 cents per kWh charge for all rate classes.

III. ADDITIONAL PCA RATE ADJUSTMENTS

A. Revenue Sharing.

Q. When was the revenue sharing mechanism originally established?

A. The revenue sharing mechanism was originally established in Case No. IPC-E-09-30 and approved in Order No. 30978, effective for the years 2009-2011. Since then, the revenue sharing mechanism has been modified and extended three times.[5] Most recently, the revenue sharing mechanism was extended indefinitely, with modifications, in Order No. 34071 in Case No. GNR-U-18-01.

Q. What are the provisions of the current revenue sharing mechanism?

A. In Case No. GNR-U-18-01, the Company filed a motion to approve a settlement stipulation ("2018 Stipulation") extending the sharing mechanism indefinitely, with modifications. The Commission approved the 2018 Stipulation in Order No. 34071.

Per the terms of the 2018 Stipulation, if the Company's actual year-end Return on Equity ("ROE") for the Idaho jurisdiction exceeds 10 percent, all amounts up to and including a 10.5 percent ROE will be shared between customers and the Company on an 80 percent and 20 percent basis, respectively, to be provided as a rate reduction to become effective at the time of the subsequent year's PCA. If the Company's Idaho jurisdictional ROE exceeds 10.5 percent, all amounts in excess of 10.5 percent will be shared 55 percent with Idaho customers as a rate reduction to become effective with the subsequent year's PCA, 25 percent will be shared with Idaho customers in the form of an offset to amounts in the Company's pension balancing account, and 20 percent will be apportioned to the Company.

[5] Order Nos. 32424, 33149 and 34071.

With regard to the amortization of Accumulated Deferred Investment Tax Credits ("ADITC"), the 2018 Stipulation allows the Company to accelerate the amortization of ADITC, in an amount up to $45 million, to achieve a maximum 9.4 percent Idaho jurisdictional ROE if the Company's year-end actual results fall below that amount for any year beginning January 1, 2020. Idaho Power may use up to $25 million of additional amortization of ADITC per year, provided the total, cumulative amount of ADITC does not exceed $45 million. Per the 2018 Stipulation, once the Company has fully amortized the $45 million of ADITC, revenue sharing will cease; however, Idaho Power may at any time request to replenish the total amount of ADITC it is permitted to amortize, and if approved by the Commission, revenue sharing would continue.

Q. What have been the results of the revenue sharing mechanism since it was implemented through 2021?

A. The Company's earnings in each year from 2011 through 2015, as well as 2018 and 2021, resulted in revenue sharing with 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, and 2020 were below the revenue sharing threshold. These amounts are detailed in Table 6 below.

Table 6	2009-2022 Revenue Sharing					
Line No.	**Revenue Sharing Component**	**2009-2011**	**2012-2014**	**2015-2019**	**2020-2022**	
1	Available ADITC For Use	$45 Million	$45 Million	$45 Million	$45 Million	
2	Customer Benefits ($ Millions):					
3	Reduction to Rates	$27.1	$22.8	$8.2	$0.6	**Total**
4	Offset to Pension Balancing Account	$20.3	$47.8	$0.0	$0.0	**2009-2022**
5	**Total**	$47.4	$70.6	$8.2	$0.6	**$126.7**

Q. Did the Company's year-end 2022 financial results warrant any action related to the existing sharing agreement per the terms of the 2018 Stipulation?

A. No. The Company's year-end 2022 financial results yielded an actual Idaho jurisdictional ROE of 9.8 percent, falling below the 10 percent ROE threshold for revenue sharing, and thus resulting in no revenue sharing with customers.

Q. Did the Company use the same methodology to determine the Idaho jurisdictional 2022 year-end ROE that was used in prior PCA filings?

A. Yes. The methodology used to determine the Company's Idaho jurisdictional 2022 year-end ROE is consistent with the methodology used for the year-end ROE determinations since the inception of the mechanism.

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

A. Yes. Exhibit No. 3 provides a step-by-step calculation of the Idaho jurisdictional ROE based on year-end 2022 financial results utilizing the Commission-approved methodology from previous PCA filings.

IV. NET CUSTOMER IMPACT

Q. What is the revenue impact of the requested PCA rate when compared with PCA rates currently in effect?

A. Attachment 2 to the Application filed contemporaneously with my testimony provides a detailed description of the overall revenue impact of this filing on each customer class. As shown in Attachment 2, applying the requested PCA rates to expected customer sales for the June 2023 through May 2024 test year[6] results in a PCA increase of $200.2 million.

Q. Given the magnitude of the increase for the 2023-2024 PCA, did the Company consider proposing any rate mitigation options?

A. Yes, though after careful consideration it was ultimately decided to not propose any rate mitigation measures in this case. While the Company is sensitive to the financial impact the proposed increase will have on its customers, it believes the potential longer-term downside

[6] Expected customer sales for the June 2023 – May 2024 test year are reduced by the amount of Micron's load forecast to be met by Black Mesa Solar generation for the reasons explained herein.

risks outweigh the near-term relief of deferring all or a portion of the requested increase.

Q. What concerns does the Company have with proposing rate mitigation measures in this case?

A. First, the Company believes that customer interests are generally best served by matching cost recovery as closely as possible with the period in which power supply costs are incurred. Additionally, mitigating rate impacts by spreading recovery over multiple years creates the possibility that the deferred collection will result in "rate pancaking" with potential future rate increases, essentially deferring an increase in the current year to create an even larger increase in the future.

Q. Is the Company's decision not to propose any rate mitigation measures in this case consistent with Commission precedent?

A. Yes. In considering the use of rate mitigation measures in prior PCA cases, the Commission has repeatedly declined to spread recovery of amounts into subsequent years citing concerns surrounding rate pancaking, appropriate matching of costs and recovery, and the overall intent of the PCA mechanism.[7]

[7] See, e.g., Order Nos. 28722, 29026, 30563, 30828, and 32821.

Q. Would Idaho Power be amenable to implementing rate mitigation measures for the 2023-2024 PCA if the Commission determines such measures are appropriate?

A. Yes. While both Idaho Power and the Commission have expressed concerns with rate mitigation measures in the past, the Company would be amenable to discussing such measures in the current filing. A two-year recovery period, for example, would reduce the rate impact from the proposed $200.2 million, or 14.68 percent increase, to an approximate $100 million, or slightly more than 7 percent, annual increase in collection spread over two years.

Q. Have you prepared a revised Schedule 55 that includes the proposed PCA rates?

A. Yes. Attachment 1 to the Application is a revised Schedule 55 and includes the proposed PCA rates in clean and legislative formats.

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

A. If approved, the 2023-2024 PCA will result in an increase in total billed revenue of approximately $200.2 million, or 14.68 percent. The Commission should approve the Company's computation of the PCA rates, the calculation of which follows the methodology that was approved in Order Nos. 30715, 33307, and 34071.

Q. Does this conclude your testimony?

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 14th day of April 2023, at Boise, Idaho.

Signed: Jessica Brady
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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-12

IDAHO POWER COMPANY

BRADY, DI
TESTIMONY

EXHIBIT NO. 1

IDAHO POWER PCA FORECAST
APRIL 1, 2023 - MARCH 31, 2024

Line No.	FERC Account	April	May	June	July	August	September	October	November	December	January	February	March	Annual
	95% Sharing Accounts													
1	**Hydroelectric Generation (MWh)**	669,893	815,724	668,995	589,237	459,802	469,487	410,852	376,407	417,821	500,561	511,721	597,496	6,487,995
	Account 536, Water for Power													
2	Total Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Account 501, Coal													
	Jim Bridger													
3	Energy (MWh)	32,400	33,480	52,800	345,000	389,280	368,000	291,648	301,087	397,342	248,168	224,151	198,028	2,881,385
4	Total Expense	$ 927,519	$ 944,093	$ 1,583,803	$ 11,771,641	$ 13,302,239	$ 12,531,704	$ 9,823,994	$ 10,124,985	$ 13,479,776	$ 9,093,109	$ 8,224,823	$ 7,120,278	$ 98,927,967
	North Valmy													
5	Energy (MWh)	0	0	0	92,982	93,606	90,587	(0)	90,586	93,606	93,606	84,547	(0)	639,520
6	Total Expense	$ 281,244	$ 281,244	$ 281,244	$ 4,036,122	$ 4,112,417	$ 4,091,354	$ 281,244	$ 4,346,310	$ 4,494,603	$ 4,527,474	$ 4,147,553	$ 281,244	$ 31,162,058
	Account 547, Other Fuel													
	Langley Gulch													
7	Energy (MWh)	139,733	217,400	207,136	210,784	211,056	173,533	104,419	215,505	227,040	226,896	209,272	219,721	2,362,496
8	Total Expense	$ 4,057,080	$ 5,606,759	$ 5,549,706	$ 6,062,379	$ 6,297,359	$ 5,184,195	$ 2,768,811	$ 8,521,863	$ 11,667,835	$ 11,483,215	$ 9,621,781	$ 8,050,424	$ 84,871,408
	Danskin													
9	Energy (MWh)	-	-	107,536	120,760	121,032	17,920	16,072	-	48,608	91,656	-	-	523,584
10	Total Expense	$ 188,260	$ 188,260	$ 4,834,354	$ 5,856,346	$ 6,077,534	$ 1,087,306	$ 880,963	$ 188,260	$ 4,036,946	$ 7,322,223	$ 188,260	$ 188,260	$ 31,036,972
	Bennett Mountain													
11	Energy (MWh)	53,120	24,600	29,792	123,504	117,792	-	26,896	-	-	-	-	-	375,704
12	Total Expense	$ 2,730,132.99	$ 1,136,502.99	$ 1,372,887.23	$ 5,862,220.99	$ 5,798,229.63	$ 92,724.99	$ 1,258,935.55	$ 92,724.99	$ 92,724.99	$ 92,724.99	$ 92,724.99	$ 92,724.99	$ 18,715,259
	Account 555, Purchased Power Non-PURPA													
13	Energy (MWh)	142,847	191,051	259,425	196,337	112,350	68,143	152,585	101,420	99,244	122,682	106,225	143,375	1,695,683
14	Total Expense	$ 7,687,629	$ 9,415,073	$ 13,232,753	$ 18,203,695	$ 14,155,915	$ 4,935,489	$ 9,776,664	$ 7,118,508	$ 8,565,313	$ 11,905,097	$ 9,371,986	$ 9,124,566	$ 123,492,688
	Account 565, 3rd Party Transmission													
15	Total Expense	$ 288,871	$ 555,684	$ 995,003	$ 1,295,183	$ 1,374,340	$ 678,713	$ 627,107	$ 442,821	$ 475,985	$ 476,827	$ 531,126	$ 222,991	$ 7,964,649
	Account 447, Surplus Sales													
16	Energy (MWh)	(164,104)	(233,311)	(50,588)	(57,706)	(29,711)	(77,912)	(18,744)	(23,789)	(3,189)	(43,366)	(130,716)	(181,682)	(1,014,817)
17	Total Expense	$ (11,881,670)	$ (11,175,499)	$ (2,179,620)	$ (7,279,357)	$ (6,124,246)	$ (12,126,073)	$ (1,354,165)	$ (2,053,469)	$ (389,477)	$ (5,433,721)	$ (13,001,139)	$ (11,193,102)	$ (84,191,539)
	100% Sharing Accounts													
	Account 555, PURPA													
18	Energy (MWh)	294,581	304,873	315,285	293,178	276,769	254,323	228,028	184,726	193,395	208,290	248,034	256,321	3,057,802
19	Total Expense	$ 15,926,928	$ 16,207,313	$ 22,389,867	$ 24,148,708	$ 23,196,742	$ 17,877,565	$ 16,195,226	$ 16,041,536	$ 17,320,985	$ 16,103,838	$ 18,694,874	$ 14,431,830	$ 218,535,412
	Account 555, Demand Response Incentives													
20	Total Expense	$ -	$ -	$ 283,373	$ 3,219,549	$ 4,926,370	$ 1,339,151	$ 185,519	$ 59,448	$ 971,098	$ -	$ -	$ -	$ 10,984,508
	95% Sharing Accounts	$ 4,279,066	$ 6,952,118	$ 25,670,130	$ 45,808,231	$ 44,993,789	$ 16,475,415	$ 24,063,555	$ 28,782,003	$ 42,423,706	$ 39,466,950	$ 19,177,114	$ 13,887,387	$ 311,979,464
	100% Sharing Accounts	$ 15,926,928	$ 16,207,313	$ 22,673,240	$ 27,368,257	$ 28,123,112	$ 19,216,716	$ 16,380,745	$ 16,100,984	$ 18,292,083	$ 16,103,838	$ 18,694,874	$ 14,431,830	$ 229,519,920
21	**Total Net Power Supply Expense**	$ 20,205,994	$ 23,159,431	$ 48,343,370	$ 73,176,488	$ 73,116,901	$ 35,692,131	$ 40,444,300	$ 44,882,987	$ 60,715,789	$ 55,570,787	$ 37,871,988	$ 28,319,217	$ 541,499,384
22	Total Generation (MWh)	1,332,575	1,587,128	1,640,969	1,971,781	1,781,687	1,441,992	1,230,500	1,269,731	1,477,055	1,491,859	1,383,951	1,414,941	18,024,169
23	Total Load (MWh)	1,168,471	1,353,817	1,590,381	1,914,075	1,751,976	1,364,081	1,211,755	1,245,943	1,473,866	1,448,493	1,253,235	1,233,259	17,009,352

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-12

IDAHO POWER COMPANY

BRADY, DI
TESTIMONY

EXHIBIT NO. 2

Power Cost Adjustment
April 2022 thru March 2023

Highlighted cells need to be updated prior to the June and July PCA entries

		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-Coal		10,847,106.68	7,386,836.10	4,111,571.46	11,388,060.41	12,934,149.36	10,862,858.85	4,311,322.69	7,381,229.78	8,669,673.61	7,626,241.65	7,359,669.84	2,077,275.31	94,955,995.74
Fuel Expense-Gas		5,526,950.57	4,507,824.70	1,959,307.24	10,394,443.73	6,195,389.72	11,777,878.94	8,000,984.36	21,045,163.64	36,970,792.16	27,818,545.94	19,969,889.01	24,150,144.27	178,317,314.28
Non-Firm Purchases		11,864,206.44	14,536,346.52	12,238,491.62	32,596,901.52	38,083,529.37	53,257,026.95	18,727,713.66	28,902,479.00	76,331,498.00	71,159,607.64	20,756,484.69	26,483,985.39	404,938,270.80
Third Party Transmission		590,965.52	1,005,756.94	1,365,288.83	1,915,820.21	1,790,013.35	1,018,981.81	884,839.05	682,107.44	822,136.83	875,468.43	962,712.15	905,086.65	12,819,177.21
Surplus Sales		(3,054,903.66)	(8,394,562.48)	(2,261,691.94)	116,995.03	(227,238.62)	(37,093,105.64)	(5,653,754.73)	(9,143,789.20)	(42,268,447.57)	(41,177,195.12)	(14,320,861.02)	(6,746,427.22)	(170,224,982.17)
Water for Power (Leases)		-	-	-	-	-	-	-	-	-	-	-	-	-
Total Actual NPSE	$	25,774,325.55	19,042,201.78	17,412,967.21	56,412,220.90	58,775,843.18	39,823,640.91	26,271,105.03	48,867,190.66	80,525,653.03	66,302,668.54	34,727,894.67	46,870,064.40	520,805,775.86
Idaho Allocation		95.6%	95.4%	95.7%	96.0%	95.9%	95.8%	95.7%	95.3%	95.2%	95.3%	95.6%	96.0%	
Net Idaho Jurisctional Actual Non-QF	$	24,640,255.23	18,166,260.50	16,664,209.62	54,155,732.06	56,366,033.61	38,151,047.99	25,141,447.51	46,570,432.70	76,660,421.68	63,186,443.12	33,199,867.30	44,995,261.82	497,897,413.14
Base Non-QF														
Fuel Expense-Coal	$	7,525,242.00	7,487,643.00	9,019,153.00	11,385,255.00	12,185,412.00	10,796,845.00	7,781,442.00	7,302,324.00	8,455,019.00	9,553,773.00	8,912,994.00	8,098,078.00	108,503,180.00
Fuel Expense-Gas	$	2,314,209.00	2,302,646.00	2,773,625.00	3,501,263.00	3,747,333.00	3,320,312.00	2,392,997.00	2,245,656.00	2,600,139.00	2,938,035.00	2,740,979.00	2,490,369.00	33,367,563.00
Non-Firm Purchases	$	4,342,083.00	4,320,388.00	5,204,073.00	6,569,319.00	7,031,012.00	6,229,805.00	4,489,910.00	4,213,459.00	4,878,566.00	5,512,549.00	5,142,819.00	4,672,610.00	62,606,593.00
Third Party Transmission	$	378,398.00	376,507.00	453,517.00	572,494.00	612,729.00	542,907.00	391,281.00	367,189.00	425,151.00	480,400.00	448,179.00	407,203.00	5,455,955.00
Surplus Sales	$	(3,588,093.00)	(3,570,166.00)	(4,300,402.00)	(5,428,577.00)	(5,810,099.00)	(5,148,019.00)	(3,710,251.00)	(3,481,805.00)	(4,031,418.00)	(4,555,312.00)	(4,249,784.00)	(3,861,227.00)	(51,735,153.00)
Water for Power (Leases)	$	165,106.00	164,281.00	197,883.00	249,796.00	267,352.00	236,886.00	170,727.00	160,216.00	185,506.00	209,613.00	195,555.00	177,676.00	2,380,597.00
Idaho Base NPSE	$	11,136,945.00	11,081,299.00	13,347,849.00	16,849,550.00	18,033,739.00	15,978,736.00	11,516,106.00	10,807,039.00	12,512,963.00	14,139,058.00	13,190,742.00	11,984,709.00	160,578,735.00
Idaho Allocation		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Net Idaho Jurisdiction 95% Items	$	10,580,097.75	10,527,234.05	12,680,456.55	16,007,072.50	17,132,052.05	15,179,799.20	10,940,300.70	10,266,687.05	11,887,314.85	13,432,105.10	12,531,204.90	11,385,473.55	152,549,798.25
Idaho Jurisdiction Change From Base	$	14,060,157.48	7,639,026.45	3,983,753.07	38,148,659.56	39,233,981.56	22,971,248.79	14,201,146.81	36,303,745.65	64,773,106.83	49,754,338.02	20,668,662.40	33,609,788.27	345,347,614.89
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%	
Net Power Supply Expense Deferral 1	$	13,357,149.61	7,257,075.13	3,784,565.42	36,241,226.58	37,272,282.48	21,822,686.35	13,491,089.47	34,488,558.37	61,534,451.49	47,266,621.12	19,635,229.28	31,929,298.86	328,080,234.16
Idaho Jurisdictional Qualifying Facility NPSE														
Actual QF (Includes Net Metering, Raft River 100% & Liquidated Damages)	$	14,958,605.05	16,068,219.34	18,990,400.71	21,624,166.85	20,132,150.98	16,190,054.78	13,070,143.71	16,510,351.76	17,309,716.19	15,523,875.98	18,000,196.38	14,949,609.43	203,327,491.16
Idaho Allocation		95.6%	95.4%	95.7%	96.0%	95.9%	95.8%	95.7%	95.3%	95.2%	95.3%	95.6%	96.0%	
Idaho Jurisctional Actual QF	$	14,300,426.43	15,329,081.25	18,173,813.48	20,759,200.18	19,306,732.79	15,510,072.48	12,508,127.53	15,734,365.23	16,478,849.81	14,794,253.81	17,208,187.74	14,351,625.05	194,454,735.78
Base QF	$	9,283,440.00	9,237,057.00	11,126,388.00	14,045,307.00	15,032,413.00	13,319,420.00	9,599,498.00	9,008,440.00	10,430,450.00	11,785,917.00	10,995,427.00	9,990,113.00	133,853,870.00
Idaho Allocation		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 Jurisdictional Base	$	8,819,268.00	8,775,204.15	10,570,068.60	13,343,041.65	14,280,792.35	12,653,449.00	9,119,523.10	8,558,018.00	9,908,927.50	11,196,621.15	10,445,655.65	9,490,607.35	127,161,176.50
Idaho Jurisdiction Change From Base	$	5,481,158.43	6,553,877.10	7,603,744.88	7,416,158.53	5,025,940.44	2,856,623.48	3,388,604.43	7,176,347.23	6,569,922.31	3,597,632.66	6,762,532.09	4,861,017.70	67,293,559.28
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%	
QF Deferral 2	$	5,481,158.43	6,553,877.10	7,603,744.88	7,416,158.53	5,025,940.44	2,856,623.48	3,388,604.43	7,176,347.23	6,569,922.31	3,597,632.66	6,762,532.09	4,861,017.70	67,293,559.28
Idaho Revenue Adjustment (SBAR)														
Actual Idaho Jurisdictional Billing Month Sales	MWh	1,005,246	1,053,812	1,178,710	1,548,306	1,721,691	1,581,973	1,118,643	1,050,588	1,227,997	1,269,362	1,221,424	1,168,371	15,146,122
Normalized Idaho Jurisdictional Billing Month Sales	MWh	947,192	953,286	1,131,686	1,370,142	1,428,766	1,300,608	1,045,495	957,864	1,081,014	1,177,663	1,101,149	1,004,027	13,498,892
Sales Change	MWh	58,054	100,526	47,024	178,164	292,925	281,365	73,148	92,724	146,983	91,699	120,275	164,344	1,647,230
% of Prior Period Billings at Old Rate	$ -	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
% of Current Period Billings at New Rate-effective 6/2015	$ 26.72	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	
Sales Adjustment Prior To Sharing @	$	(1,551,202.88)	(2,686,048.71)	(1,256,481.28)	(4,760,542.08)	(7,826,942.72)	(7,518,072.80)	(1,954,514.56)	(2,477,585.28)	(3,927,385.76)	(2,450,197.28)	(3,213,748.00)	(4,391,267.63)	(44,013,988.98)
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	$	(1,473,642.74)	(2,551,746.27)	(1,193,657.22)	(4,522,514.98)	(7,435,595.58)	(7,142,169.16)	(1,856,788.83)	(2,353,706.02)	(3,731,016.47)	(2,327,687.42)	(3,053,060.60)	(4,171,704.25)	(41,813,289.54)
Idaho Jurisdcitional Demand Response Incentive Payments														
Idaho Actual Demand Response	$	-	-	163,366.82	2,073,169.22	2,843,974.65	2,121,623.76	628,735.75	479,437.58	1,020.00	14.35	85.35	101.34	8,311,528.82
Idaho Base Demand Response	$	780,401.00	776,502.00	935,327.00	1,180,702.00	1,263,682.00	1,119,681.00	806,970.00	757,284.00	876,823.00	990,769.00	924,317.00	839,807.00	11,252,265.00
Change From Base	$	(780,401.00)	(776,502.00)	(771,960.18)	892,467.22	1,580,292.65	1,001,942.76	(178,234.25)	(277,846.42)	(875,803.00)	(990,754.65)	(924,231.65)	(839,705.66)	(2,940,736.18)
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	$	(780,401.00)	(776,502.00)	(771,960.18)	892,467.22	1,580,292.65	1,001,942.76	(178,234.25)	(277,846.42)	(875,803.00)	(990,754.65)	(924,231.65)	(839,705.66)	(2,940,736.18)
Idaho Miscellaneous Revenue														
System Emission Allowance Sales Credit	$	-	-	-	-	-	-	-	-	-	-	-	-	-
System Renewable Energy Credit Sales	$	(1,168,040.31)	809.96	171.78	181.81	(1,183,377.60)	669.95	(83,462.81)	218.59	(738,019.94)	(3,294,293.02)	(4,123,273.82)	(63,679.79)	(10,652,095.20)
Revenue Subtotal	$	(1,168,040.31)	809.96	171.78	181.81	(1,183,377.60)	669.95	(83,462.81)	218.59	(738,019.94)	(3,294,293.02)	(4,123,273.82)	(63,679.79)	(10,652,095.20)
Idaho Allocation		95.6%	95.4%	95.7%	96.0%	95.9%	95.8%	95.7%	95.3%	95.2%	95.3%	95.6%	96.0%	
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	$	(1,060,814.21)	734.07	156.17	165.81	(1,078,116.16)	609.72	(75,880.21)	197.90	(667,465.23)	(2,982,488.19)	(3,744,757.28)	(58,075.97)	(9,665,733.58)

Idaho EIM Participation Costs														
Return on EIM Capital Investment	$	33,103.18	32,402.30	31,701.42	31,000.54	30,299.65	29,598.77	28,897.89	28,197.01	27,496.13	26,795.25	26,094.37	25,393.49	350,980.01
Operating Expenses	$	196,675.42	205,717.68	167,186.10	167,362.06	196,300.92	166,352.29	176,893.06	143,446.00	179,859.42	225,077.65	195,294.16	214,835.67	2,235,000.41
Revenue Subtotal	$	229,778.59	238,119.98	198,887.52	198,362.60	226,600.57	195,951.07	205,790.95	171,643.02	207,355.55	251,872.90	221,388.53	240,229.16	2,585,980.43
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%	
EIM Revenue Requirement ⑥	$	218,289.66	226,213.98	188,943.14	188,444.47	215,270.54	186,153.52	195,501.40	163,060.87	196,987.77	239,279.26	210,319.11	228,217.70	2,456,681.42
TOTAL DEFERRAL (Sum of ①-⑥)	**$**	**15,741,739.75**	**10,709,652.01**	**9,611,792.21**	**40,215,947.63**	**35,580,074.37**	**18,725,846.67**	**14,964,292.01**	**39,196,611.93**	**63,027,076.87**	**44,802,602.78**	**18,886,030.95**	**31,949,048.38**	**343,410,715.56**

PCA Forecasted Revenues														
Actual Idaho Jurisdictional Billing Month Sales	MWh	1,005,246	1,053,812	1,178,710	1,548,306	1,721,691	1,581,973	1,118,643	1,050,588	1,227,997	1,269,362	1,221,424	1,168,371	15,146,122
% of Prior Period Billings at Old Rate 6/1/2021	$ 7.83	100.000%	100.000%	60.185%	1.389%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
% of Current Period Billings at New Rate - 6/1/2022	$ 8.79	0.000%	0.000%	39.800%	98.600%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	
Forecast Rate Revenues ⑦		(8,839,128.20)	(9,266,166.94)	(11,441,018.36)	(17,409,566.17)	(19,407,095.97)	(17,972,798.81)	(12,708,913.52)	(11,935,736.88)	(13,951,273.90)	(14,421,225.91)	(13,876,598.56)	(13,273,861.21)	(164,503,384.43)

PCA Balancing Account Balance

Monthly Interest Rate (Annual 1% for 2022, 2% for 2023)	%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.1667%	0.1667%	0.1667%	1.2500%
Beginning Balance	$	38,669,525.55	46,832,766.34	49,603,036.48	47,089,846.29	65,914,170.36	77,522,098.47	74,442,372.54	73,918,880.54	98,574,262.10	144,614,010.89	172,012,445.47	174,207,820.07	38,669,525.55
2022-2023 Incremental Deferral (Sum of ①-⑥ above		15,741,739.75	10,709,652.01	9,611,792.21	40,215,947.63	35,580,074.37	18,725,846.67	14,964,292.01	39,196,611.93	63,027,076.87	44,802,602.78	18,886,030.95	31,949,048.38	343,410,715.56
2022-2023 PCA Forecast Revenues (Collections) ⑦ above		(8,839,128.20)	(9,266,166.94)	(11,441,018.36)	(17,409,566.17)	(19,407,095.97)	(17,972,798.81)	(12,708,913.52)	(11,935,736.88)	(13,951,273.90)	(14,421,225.91)	(13,876,598.56)	(13,273,861.21)	(164,503,384.43)
2022-2023 PCA Prior Balance Revenues (Collections)		1,228,404.64	1,287,757.76	(153,917.98)	(4,021,298.93)	(4,619,978.77)	(3,897,375.54)	(2,840,905.80)	(2,667,092.56)	(3,118,199.40)	(3,223,965.64)	(3,100,745.20)	(2,967,784.99)	(28,095,102.41)
Revenue Sharing - Order No.		-	-	(571,381.92)	-	-	-	-	-	-	-	-	-	(571,381.92)
DSM Rider Forecasted Surplus Funds - Order No.		-	-	-	-	-	-	-	-	-	-	-	-	-
2022-2023 Ending Balance Without Current Month Interest		46,800,541.74	49,564,009.17	47,048,510.43	65,874,928.82	77,467,169.99	74,377,770.79	73,856,845.23	98,512,663.03	144,531,865.67	171,771,422.12	173,921,132.66	189,915,222.25	188,910,372.35
Current Month Interest		32,224.60	39,027.31	41,335.86	39,241.54	54,928.48	64,601.75	62,035.31	61,599.07	82,145.22	241,023.35	286,687.41	290,346.37	1,295,196.27
2022-2023 Ending Deferral Balance	**$**	**46,832,766.34**	**49,603,036.48**	**47,089,846.29**	**65,914,170.36**	**77,522,098.47**	**74,442,372.54**	**73,918,880.54**	**98,574,262.10**	**144,614,010.89**	**172,012,445.47**	**174,207,820.07**	**190,205,568.62**	**190,205,568.62**

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

Idaho Billed Sales	MWh	1,005,246	1,053,812	1,178,710	1,548,306	1,721,691	1,581,973	1,118,643	1,050,588	1,227,997	1,269,362	1,221,424	1,168,371	15,146,122
Oregon Billed Sales	MWh	46,427	50,553	53,082	63,743	72,727	68,968	50,421	51,906	62,339	62,037	56,639	49,302	688,143
Total	MWh	1,051,673	1,104,364	1,231,792	1,612,049	1,794,417	1,650,941	1,169,064	1,102,494	1,290,336	1,331,399	1,278,063	1,217,673	15,834,266
Idaho % Billed Sales		95.6%	95.4%	95.7%	96.0%	95.9%	95.8%	95.7%	95.3%	95.2%	95.3%	95.6%	96.0%	
Oregon % Billed Sales		4.4%	4.6%	4.3%	4.0%	4.1%	4.2%	4.3%	4.7%	4.8%	4.7%	4.4%	4.0%	

Power Cost Adjustment Input Sheet
April 2022 thru March 2023

	Source	April	May	June	July	August	September	October	November	December	January	February	March	Total
Actual Idaho Jurisdictional Billing Month Sales (Mwh)	NCUST - Fin Accntng	1,005,246	1,053,812	1,178,710	1,548,306	1,721,691	1,581,973	1,118,643	1,050,588	1,227,997	1,269,362	1,221,424	1,168,371	15,146,122
Actual Idaho Jurisdictional Calendar Month Sales (Mwh)	NCUST - Fin Accntng	1,030,080	1,151,009	1,309,649	1,770,115	1,656,873	1,267,327	1,022,769	1,159,427	1,297,005	1,255,296	1,120,338	1,156,785	15,196,672
Actual Oregon Jurisdictional Billing Month Sales (Mwh)	NCUST - Fin Accntng	46,427	50,553	53,082	63,743	72,727	68,968	50,421	51,906	62,339	62,037	56,639	49,302	688,143
Surplus Sales (447)	Purchases and Sales Sheet-Christy Van Paepeghem	(3,054,903.66)	(8,394,562.48)	(2,261,691.94)	116,995.03	(227,238.62)	(37,093,105.64)	(5,653,754.73)	(9,143,789.20)	(42,268,447.57)	(41,177,195.12)	(14,320,861.02)	(6,746,427.22)	(170,224,982.17)
Total Purchased Power	Purchases and Sales Sheet-Christy Van Paepeghem	12,191,275.94	14,772,851.86	12,670,837.76	32,482,332.00	37,703,740.06	53,511,436.21	19,164,182.26	29,443,672.31	76,511,844.14	71,435,626.01	21,313,471.02	26,579,956.71	407,781,226.28
Less Raft River Geothermal 100% PCA	Purchases and Sales Sheet-Christy Van Paepeghem	421,475.64	406,842.04	527,600.39	589,330.74	528,975.59	464,130.18	527,125.14	699,354.59	724,962.11	614,089.57	559,327.26	452,143.91	6,515,357.16
Net Non-Firm Purchases - Including Telecaset & Raft River 95%(Acct 555000)		11,769,800.30	14,366,009.82	12,143,237.37	31,893,001.26	37,174,764.47	53,047,306.03	18,637,057.12	28,744,317.72	75,786,882.03	70,821,536.44	20,754,143.76	26,127,812.80	401,265,869.12
Purchased Power Transmission Losses (555050)	Purchases and Sales Sheet-Christy Van Paepeghem	92,639.60	168,488.10	92,879.25	696,566.17	894,801.42	199,583.40	85,663.16	155,437.39	541,970.00	335,938.83	265.59	354,785.32	3,619,018.23
Oregon Solar	Purchases and Sales Sheet-Christy Van Paepeghem	1,766.54	1,848.60	2,375.00	7,334.09	13,963.48	10,137.52	4,993.38	2,723.89	2,645.97	2,132.37	2,075.34	1,387.27	53,383.45
Total Non-Firm Purchases		11,864,206.44	14,536,346.52	12,238,491.62	32,596,901.52	38,083,529.37	53,257,026.95	18,727,713.66	28,902,479.00	76,331,498.00	71,159,607.64	20,756,484.69	26,483,985.39	404,938,270.80
CSPP Expense (555070)	Purchases and Sales Sheet-Christy Van Paepeghem	14,537,129.41	15,661,377.30	18,462,800.32	21,066,477.95	19,603,175.39	15,725,924.60	12,556,172.32	15,810,957.17	16,803,693.41	14,690,847.08	17,440,869.12	14,622,620.54	196,982,044.61
Net Metering (555101) Order No. 29094	Purchases and Sales Sheet-Christy Van Paepeghem	-	-	-	-	-	-	-	-	-	-	-	-	-
Raft River 100%	Purchases and Sales Sheet-Christy Van Paepeghem	421,475.64	406,842.04	527,600.39	589,330.74	528,975.59	464,130.18	527,125.14	699,354.59	724,962.11	614,089.57	559,327.26	452,143.91	6,515,357.16
Liquidated Damages (555080)	Purchases and Sales Sheet-Christy Van Paepeghem	-			(31,641.84)			(13,153.75)	40.00	(218,939.33)	218,939.33	-	(125,155.02)	(169,910.61)
Total QF		14,958,605.05	16,068,219.34	18,990,400.71	21,624,166.85	20,132,150.98	16,190,054.78	13,070,143.71	16,510,351.76	17,309,716.19	15,523,875.98	18,000,196.38	14,949,609.43	203,327,491.16
Demand Response Incentive Payments	Purchases and Sales Sheet-Christy Van Paepeghem	-	-	163,366.82	2,073,169.22	2,843,974.65	2,121,623.76	628,735.75	479,437.58	1,020.00	14.35	85.35	101.34	8,311,528.82
Third Party Transmission (565000)	Purchases and Sales Sheet-Christy Van Paepeghem	590,965.52	1,005,756.94	1,365,288.83	1,915,820.21	1,790,013.35	1,018,981.81	884,839.05	682,107.44	822,136.83	875,468.43	962,712.15	905,086.65	12,819,177.21
Fuel Expense - Coal (Account 501)	Purchases and Sales Sheet-Christy Van Paepeghem	10,847,106.68	7,386,836.10	4,111,571.46	11,388,060.41	12,934,149.36	10,862,858.85	4,311,322.69	7,381,229.78	8,669,673.61	7,626,241.65	7,359,669.84	2,077,275.31	94,955,995.74
Fuel Expense - Gas - Capacity & Fuel (547101 - 547103. 547105)	Purchases and Sales Sheet-Christy Van Paepeghem	5,526,950.57	4,507,824.70	1,959,307.24	10,394,443.73	6,195,389.72	11,777,878.94	8,000,984.36	21,045,163.64	36,970,792.16	27,818,545.94	19,969,889.01	24,150,144.27	178,317,314.28
Water Lease Expense (Acct 536003)	Peoplesoft query - Cathy Campbell	-	-	-	-	-	-	-	-	-	-	-	-	-
Emission Allowance Sales	Peoplesoft query - Cathy Campbell	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Energy Credits	Christy Van Paepeghem	(1,168,040.31)	809.96	171.78	181.81	(1,183,377.60)	669.95	(83,462.81)	218.59	(738,019.94)	(3,294,293.02)	(4,123,273.82)	(63,679.79)	(10,652,095.20)
True-up Revenues	YYYY PCA from Data Warehouse - Fin Accntng	(1,228,404.64)	(1,287,757.76)	153,917.98	4,021,298.93	4,619,978.77	3,897,375.54	2,840,905.80	2,667,092.56	3,118,199.40	3,223,965.64	3,100,745.20	2,967,784.99	28,095,102.41
Forecast Revenues	YYYY PCA from Data Warehouse - Fin Accntng	8,839,128.20	9,266,166.94	11,441,018.36	17,409,566.17	19,407,095.97	17,972,798.81	12,708,913.52	11,935,736.88	13,951,273.90	14,421,225.91	13,876,598.56	13,273,861.21	164,503,384.43

Tab is 100% locked down, with exception of inputs, which have been traced to source

	April	May	June	July	August	September	October	November	December	January	February	March	Total
Normalized Idaho Jurisdictional Billed Sales (Mwh)	947,192	953,286	1,131,686	1,370,142	1,428,766	1,300,608	1,045,495	957,864	1,081,014	1,177,663	1,101,149	1,004,027	13,498,892
Normalized Idaho Jurisdictional Calendar Month Sales (Mwh)	911,298	1,108,897	1,213,542	1,521,656	1,379,463	1,113,295	955,414	980,350	1,177,700	1,169,731	990,746	982,290	13,504,382
Base Non-QF													
Fuel Expense-Coal	7,525,242.00	7,487,643.00	9,019,153.00	11,385,255.00	12,185,412.00	10,796,845.00	7,781,442.00	7,302,324.00	8,455,019.00	9,553,773.00	8,912,994.00	8,098,078.00	108,503,180.00
Fuel Expense-Gas	2,314,209.00	2,302,646.00	2,773,625.00	3,501,263.00	3,747,333.00	3,320,312.00	2,392,997.00	2,245,656.00	2,600,139.00	2,938,035.00	2,740,979.00	2,490,369.00	33,367,563.00
Non-Firm Purchases	4,342,083.00	4,320,388.00	5,204,073.00	6,569,319.00	7,031,012.00	6,229,805.00	4,489,910.00	4,213,459.00	4,878,566.00	5,512,549.00	5,142,819.00	4,672,610.00	62,606,593.00
Third Party Transmission	378,398.00	376,507.00	453,517.00	572,494.00	612,729.00	542,907.00	391,281.00	367,189.00	425,151.00	480,400.00	448,179.00	407,203.00	5,455,955.00
Surplus Sales	(3,588,093.00)	(3,570,166.00)	(4,300,402.00)	(5,428,577.00)	(5,810,099.00)	(5,148,019.00)	(3,710,251.00)	(3,481,805.00)	(4,031,418.00)	(4,555,312.00)	(4,249,784.00)	(3,861,227.00)	(51,735,153.00)
Water for Power (Leases)	165,106.00	164,281.00	197,883.00	249,796.00	267,352.00	236,886.00	170,727.00	160,216.00	185,506.00	209,613.00	195,555.00	177,676.00	2,380,597.00
Net 95% Items	11,136,945.00	11,081,299.00	13,347,849.00	16,849,550.00	18,033,739.00	15,978,736.00	11,516,106.00	10,807,039.00	12,512,963.00	14,139,058.00	13,190,742.00	11,984,709.00	160,578,735.00
Base Demand Response Incentive Payments	780,401	776,502	935,327	1,180,702	1,263,682	1,119,681	806,970	757,284	876,823	990,769	924,317	839,807	11,252,265
Base QF	9,283,440	9,237,057	11,126,388	14,045,307	15,032,413	13,319,420	9,599,498	9,008,440	10,430,450	11,785,917	10,995,427	9,990,113	133,853,870

Idaho Power Company
Western EIM Participation Costs
Idaho Jurisdictional Revenue Requirement

RATE BASE	**Mar-22**
Electric Plant in Service	
Intangible Plant	$ 5,792,702
Production Plant	1153936.874
Transmission Plant	1204191.691
Distribution Plant	0
General Plant	0
Total Electric Plant in Service	8150830.238
Less: Accumulated Depreciation	205803.1395
Less: Amortization of Other Plant	4152990.097
Net Electric Plant in Service	3792037.002
Less: Customer Adv for Construction	0
Less: Accumulated Deferred Income Taxes	38996.09787
Add: Plant Held for Future Use	0
Add: Working Capital	0
Add: Other Deferred Amounts	0
Add: Subsidiary Rate Base	
TOTAL COMBINED RATE BASE	$ 3,753,041

NET INCOME	
Operating Revenues	
Sales Revenues	0
Other Operating Revenues	0
Total Operating Revenues	$ -
Operating Expenses	
Operation and Maintenance Expenses	$ 158,056
Depreciation Expenses	5,499
Amortization of Limited Term Plant	34,967
Taxes Other Than Income	3,429
Regulatory Debits/Credits	
Provision for Deferred Income Taxes	(5,278)
Investment Tax Credit Adjustment	0
Federal Income Taxes	(38,822)
State Income Taxes	(11,800)
Total Operating Expenses	$ 146,051
Operating Income	-146051.1616
Add: IERCO Operating Income	0
Consolidated Operating Income	$ (146,051)
Rate of Return as filed	-3.89%
Annual Authorized Rate of Return	7.86%
Earnings Impact	170633.5795
Net-to-Gross Tax Multiplier	1.347
Monthly Revenue Requirement	**$ 229,779**

Idaho Power Company
Western EIM Participation Costs
Idaho Jurisdictional Revenue Requirement

RATE BASE	**May-22**
Electric Plant in Service	
Intangible Plant	$ 5,792,702
Production Plant	1153936.874
Transmission Plant	1204191.691
Distribution Plant	0
General Plant	0
Total Electric Plant in Service	8150830.238
Less: Accumulated Depreciation	211302.1158
Less: Amortization of Other Plant	4187956.646
Net Electric Plant in Service	3751571.476
Less: Customer Adv for Construction	0
Less: Accumulated Deferred Income Taxes	77992.19575
Add: Plant Held for Future Use	0
Add: Working Capital	0
Add: Other Deferred Amounts	0
Add: Subsidiary Rate Base	
TOTAL COMBINED RATE BASE	$ 3,673,579

NET INCOME	
Operating Revenues	
Sales Revenues	0
Other Operating Revenues	0
Total Operating Revenues	$ -
Operating Expenses	
Operation and Maintenance Expenses	$ 167,098
Depreciation Expenses	5,499
Amortization of Limited Term Plant	34,967
Taxes Other Than Income	3,429
Regulatory Debits/Credits	
Provision for Deferred Income Taxes	(5,278)
Investment Tax Credit Adjustment	0
Federal Income Taxes	(40,607)
State Income Taxes	(12,342)
Total Operating Expenses	$ 152,766
Operating Income	-152765.948
Add: IERCO Operating Income	0
Consolidated Operating Income	$ (152,766)
Rate of Return as filed	-4.16%
Annual Authorized Rate of Return	7.86%
Earnings Impact	176827.8923
Net-to-Gross Tax Multiplier	1.347
Monthly Revenue Requirement	**$ 238,120**

Idaho Power Company
Western EIM Participation Costs
Idaho Jurisdictional Revenue Requirement

RATE BASE	
Electric Plant in Service	
Intangible Plant	$ 5,792,702
Production Plant	1153936.874
Transmission Plant	1204191.691
Distribution Plant	0
General Plant	0
Total Electric Plant in Service	8150830.238
Less: Accumulated Depreciation	216801.0921
Less: Amortization of Other Plant	4222923.196
Net Electric Plant in Service	3711105.951
Less: Customer Adv for Construction	0
Less: Accumulated Deferred Income Taxes	116988.2936
Add: Plant Held for Future Use	0
Add: Working Capital	0
Add: Other Deferred Amounts	0
Add: Subsidiary Rate Base	
TOTAL COMBINED RATE BASE	$ 3,594,118
NET INCOME	
Operating Revenues	
Sales Revenues	0
Other Operating Revenues	0
Total Operating Revenues	$ -
Operating Expenses	
Operation and Maintenance Expenses	$ 128,567
Depreciation Expenses	5,499
Amortization of Limited Term Plant	34,967
Taxes Other Than Income	3,429
Regulatory Debits/Credits	
Provision for Deferred Income Taxes	(5,278)
Investment Tax Credit Adjustment	0
Federal Income Taxes	(33,001)
State Income Taxes	(10,031)
Total Operating Expenses	$ 124,152
Operating Income	-124152.3972
Add: IERCO Operating Income	0
Consolidated Operating Income	$ (124,152)
Rate of Return as filed	-3.45%

Annual Authorized Rate of Return		7.86%
Earnings Impact		147693.8678
Net-to-Gross Tax Multiplier		1.347
Monthly Revenue Requirement	**$**	**198,888**

Components of Monthly Revenue Requirement

Return on Rate Base	$	23,541
Gross-up factor		1.347
Total Monthly Rev Req for Return on Rate Base		**31,701**
Start-up Costs Amortization		0
Gross-up factor		1.347
Total Monthly Rev Req for Start-Up Costs		**0**
Other Operating Expense		124,152
Gross-up factor		1.347
Total Monthly Rev Req for Other Operating Exp		**167,186**
Total Monthly Revenue Requirement	**$**	**198,888**

Idaho Power Company
Western EIM Participation Costs
Idaho Jurisdictional Revenue Requirement

RATE BASE	
Electric Plant in Service	
Intangible Plant	$ 5,792,702
Production Plant	1153936.874
Transmission Plant	1204191.691
Distribution Plant	0
General Plant	0
Total Electric Plant in Service	8150830.238
Less: Accumulated Depreciation	222300.0684
Less: Amortization of Other Plant	4257889.745
Net Electric Plant in Service	3670640.425
Less: Customer Adv for Construction	0
Less: Accumulated Deferred Income Taxes	155984.3915
Add: Plant Held for Future Use	0
Add: Working Capital	0
Add: Other Deferred Amounts	0
Add: Subsidiary Rate Base	
TOTAL COMBINED RATE BASE	$ 3,514,656

NET INCOME	
Operating Revenues	
Sales Revenues	0
Other Operating Revenues	0
Total Operating Revenues	$ -
Operating Expenses	
Operation and Maintenance Expenses	$ 128,743
Depreciation Expenses	5,499
Amortization of Limited Term Plant	34,967
Taxes Other Than Income	3,429
Regulatory Debits/Credits	
Provision for Deferred Income Taxes	(5,278)
Investment Tax Credit Adjustment	0
Federal Income Taxes	(33,035)
State Income Taxes	(10,041)
Total Operating Expenses	$ 124,283
Operating Income	-124283.0649
Add: IERCO Operating Income	0
Consolidated Operating Income	$ (124,283)
Rate of Return as filed	-3.54%

Annual Authorized Rate of Return		7.86%
Earnings Impact		147304.0619
Net-to-Gross Tax Multiplier		1.347
Monthly Revenue Requirement	**$**	**198,363**

Components of Monthly Revenue Requirement

Return on Rate Base	$	23,021
Gross-up factor		1.347
Total Monthly Rev Req for Return on Rate Base		**31,001**
Start-up Costs Amortization		0
Gross-up factor		1.347
Total Monthly Rev Req for Start-Up Costs		**0**
Other Operating Expense		124,283
Gross-up factor		1.347
Total Monthly Rev Req for Other Operating Exp		**167,362**
Total Monthly Revenue Requirement	**$**	**198,363**

Idaho Power Company
Western EIM Participation Costs
Idaho Jurisdictional Revenue Requirement

RATE BASE	
Electric Plant in Service	
Intangible Plant	$ 5,792,702
Production Plant	1153936.874
Transmission Plant	1204191.691
Distribution Plant	0
General Plant	0
Total Electric Plant in Service	8150830.238
Less: Accumulated Depreciation	227799.0447
Less: Amortization of Other Plant	4292856.294
Net Electric Plant in Service	3630174.9
Less: Customer Adv for Construction	0
Less: Accumulated Deferred Income Taxes	194980.4894
Add: Plant Held for Future Use	0
Add: Working Capital	0
Add: Other Deferred Amounts	0
Add: Subsidiary Rate Base	
TOTAL COMBINED RATE BASE	$ 3,435,194
NET INCOME	
Operating Revenues	
Sales Revenues	0
Other Operating Revenues	0
Total Operating Revenues	$ -
Operating Expenses	
Operation and Maintenance Expenses	$ 157,682
Depreciation Expenses	5,499
Amortization of Limited Term Plant	34,967
Taxes Other Than Income	3,429
Regulatory Debits/Credits	
Provision for Deferred Income Taxes	(5,278)
Investment Tax Credit Adjustment	0
Federal Income Taxes	(38,748)
State Income Taxes	(11,777)
Total Operating Expenses	$ 145,773
Operating Income	-145773.0579
Add: IERCO Operating Income	0
Consolidated Operating Income	$ (145,773)
Rate of Return as filed	-4.24%
Annual Authorized Rate of Return	7.86%
Earnings Impact	168273.5813
Net-to-Gross Tax Multiplier	1.347
Monthly Revenue Requirement	**$ 226,601**

Components of Monthly Revenue Requirement

Return on Rate Base	$ 22,501
Gross-up factor	1.347
Total Monthly Rev Req for Return on Rate Base	**30,300**
Start-up Costs Amortization	0
Gross-up factor	1.347
Total Monthly Rev Req for Start-Up Costs	**0**
Other Operating Expense	145,773
Gross-up factor	1.347
Total Monthly Rev Req for Other Operating Exp	**196,301**
Total Monthly Revenue Requirement	**$ 226,601**

Idaho Power Company
Western EIM Participation Costs
Idaho Jurisdictional Revenue Requirement

RATE BASE	
Electric Plant in Service	
Intangible Plant	$ 5,792,702
Production Plant	1153936.874
Transmission Plant	1204191.691
Distribution Plant	0
General Plant	0
Total Electric Plant in Service	8150830.238
Less: Accumulated Depreciation	233298.021
Less: Amortization of Other Plant	4327822.843
Net Electric Plant in Service	3589709.374
Less: Customer Adv for Construction	0
Less: Accumulated Deferred Income Taxes	233976.5872
Add: Plant Held for Future Use	0
Add: Working Capital	0
Add: Other Deferred Amounts	0
Add: Subsidiary Rate Base	
TOTAL COMBINED RATE BASE	$ 3,355,733

NET INCOME	
Operating Revenues	
Sales Revenues	0
Other Operating Revenues	0
Total Operating Revenues	$ -
Operating Expenses	
Operation and Maintenance Expenses	$ 127,733
Depreciation Expenses	5,499
Amortization of Limited Term Plant	34,967
Taxes Other Than Income	3,429
Regulatory Debits/Credits	
Provision for Deferred Income Taxes	(5,278)
Investment Tax Credit Adjustment	0
Federal Income Taxes	(32,836)
State Income Taxes	(9,981)
Total Operating Expenses	$ 123,533
Operating Income	-123533.2124
Add: IERCO Operating Income	0
Consolidated Operating Income	$ (123,533)
Rate of Return as filed	-3.68%

Annual Authorized Rate of Return		7.86%
Earnings Impact		145513.2622
Net-to-Gross Tax Multiplier		1.347
Monthly Revenue Requirement	**$**	**195,951**

Components of Monthly Revenue Requirement

Return on Rate Base	$	21,980
Gross-up factor		1.347
Total Monthly Rev Req for Return on Rate Base		**29,599**
Start-up Costs Amortization		0
Gross-up factor		1.347
Total Monthly Rev Req for Start-Up Costs		**0**
Other Operating Expense		123,533
Gross-up factor		1.347
Total Monthly Rev Req for Other Operating Exp		**166,352**
Total Monthly Revenue Requirement	**$**	**195,951**

Idaho Power Company
Western EIM Participation Costs
Idaho Jurisdictional Revenue Requirement

RATE BASE		
Electric Plant in Service		
Intangible Plant	$	5,792,702
Production Plant		1153936.874
Transmission Plant		1204191.691
Distribution Plant		0
General Plant		0
Total Electric Plant in Service		8150830.238
Less: Accumulated Depreciation		238796.9973
Less: Amortization of Other Plant		4362789.392
Net Electric Plant in Service		3549243.849
Less: Customer Adv for Construction		0
Less: Accumulated Deferred Income Taxes		272972.6851
Add: Plant Held for Future Use		0
Add: Working Capital		0
Add: Other Deferred Amounts		0
Add: Subsidiary Rate Base		
TOTAL COMBINED RATE BASE	$	3,276,271
NET INCOME		
Operating Revenues		
Sales Revenues		0
Other Operating Revenues		0
Total Operating Revenues	$	-
Operating Expenses		
Operation and Maintenance Expenses	$	138,274
Depreciation Expenses		5,499
Amortization of Limited Term Plant		34,967
Taxes Other Than Income		3,429
Regulatory Debits/Credits		
Provision for Deferred Income Taxes		(5,278)
Investment Tax Credit Adjustment		0
Federal Income Taxes		(34,917)
State Income Taxes		(10,613)
Total Operating Expenses	$	131,361
Operating Income		-131360.7815
Add: IERCO Operating Income		0
Consolidated Operating Income	$	(131,361)
Rate of Return as filed		-4.01%

Annual Authorized Rate of Return		7.86%
Earnings Impact		152820.3576
Net-to-Gross Tax Multiplier		1.347
Monthly Revenue Requirement	**$**	**205,791**

Components of Monthly Revenue Requirement

Return on Rate Base	$	21,460
Gross-up factor		1.347
Total Monthly Rev Req for Return on Rate Base		**28,898**
Start-up Costs Amortization		0
Gross-up factor		1.347
Total Monthly Rev Req for Start-Up Costs		**0**
Other Operating Expense		131,361
Gross-up factor		1.347
Total Monthly Rev Req for Other Operating Exp		**176,893**
Total Monthly Revenue Requirement	**$**	**205,791**

Idaho Power Company
Western EIM Participation Costs
Idaho Jurisdictional Revenue Requirement

RATE BASE		
Electric Plant in Service		
Intangible Plant	$	5,792,702
Production Plant		1153936.874
Transmission Plant		1204191.691
Distribution Plant		0
General Plant		0
Total Electric Plant in Service		8150830.238
Less: Accumulated Depreciation		244295.9736
Less: Amortization of Other Plant		4397755.941
Net Electric Plant in Service		3508778.324
Less: Customer Adv for Construction		0
Less: Accumulated Deferred Income Taxes		311968.783
Add: Plant Held for Future Use		0
Add: Working Capital		0
Add: Other Deferred Amounts		0
Add: Subsidiary Rate Base		
TOTAL COMBINED RATE BASE	$	3,196,810

NET INCOME		
Operating Revenues		
Sales Revenues		0
Other Operating Revenues		0
Total Operating Revenues	$	-
Operating Expenses		
Operation and Maintenance Expenses	$	104,827
Depreciation Expenses		5,499
Amortization of Limited Term Plant		34,967
Taxes Other Than Income		3,429
Regulatory Debits/Credits		
Provision for Deferred Income Taxes		(5,278)
Investment Tax Credit Adjustment		0
Federal Income Taxes		(28,314)
State Income Taxes		(8,606)
Total Operating Expenses	$	106,523
Operating Income		-106522.9996
Add: IERCO Operating Income		0
Consolidated Operating Income	$	(106,523)
Rate of Return as filed		-3.33%

Annual Authorized Rate of Return		7.86%
Earnings Impact		127462.1021
Net-to-Gross Tax Multiplier		1.347
Monthly Revenue Requirement	**$**	**171,643**

Components of Monthly Revenue Requirement

Return on Rate Base	$	20,939
Gross-up factor		1.347
Total Monthly Rev Req for Return on Rate Base		**28,197**
Start-up Costs Amortization		0
Gross-up factor		1.347
Total Monthly Rev Req for Start-Up Costs		**0**
Other Operating Expense		106,523
Gross-up factor		1.347
Total Monthly Rev Req for Other Operating Exp		**143,446**
Total Monthly Revenue Requirement	**$**	**171,643**

Idaho Power Company
Western EIM Participation Costs
Idaho Jurisdictional Revenue Requirement

RATE BASE	
Electric Plant in Service	
Intangible Plant	5,792,701.67
Production Plant	1,153,936.87
Transmission Plant	1,204,191.69
Distribution Plant	-
General Plant	-
Total Electric Plant in Service	8,150,830.24
Less: Accumulated Depreciation	249,794.95
Less: Amortization of Other Plant	4,432,722.49
Net Electric Plant in Service	3,468,312.80
Less: Customer Adv for Construction	-
Less: Accumulated Deferred Income Taxes	350,964.88
Add: Plant Held for Future Use	-
Add: Working Capital	-
Add: Other Deferred Amounts	-
Add: Subsidiary Rate Base	
TOTAL COMBINED RATE BASE	3,117,347.92
NET INCOME	
Operating Revenues	
Sales Revenues	-
Other Operating Revenues	-
Total Operating Revenues	-
Operating Expenses	
Operation and Maintenance Expenses	141,240.14
Depreciation Expenses	5,498.98
Amortization of Limited Term Plant	34,966.55
Taxes Other Than Income	3,429.02
Regulatory Debits/Credits	
Provision for Deferred Income Taxes	(5,277.88)
Investment Tax Credit Adjustment	-
Federal Income Taxes	(35,502.25)
State Income Taxes	(10,790.96)
Total Operating Expenses	133,563.60
Operating Income	(133,563.60)
Add: IERCO Operating Income	-
Consolidated Operating Income	(133,563.60)
Rate of Return as filed	(0.04)

Annual Authorized Rate of Return	0.08
Earnings Impact	153,982.23
Net-to-Gross Tax Multiplier	1.35
Monthly Revenue Requirement	**207,355.55**

Components of Monthly Revenue Requirement

Return on Rate Base	20,418.63
Gross-up factor	1.35
Total Monthly Rev Req for Return on Rate Base	**27,496.13**
Start-up Costs Amortization	-
Gross-up factor	1.35
Total Monthly Rev Req for Start-Up Costs	**-**
Other Operating Expense	133,563.60
Gross-up factor	1.35
Total Monthly Rev Req for Other Operating Exp	**179,859.42**
Total Monthly Revenue Requirement	**207,355.55**

Idaho Power Company
Western EIM Participation Costs
Idaho Jurisdictional Revenue Requirement

RATE BASE	
Electric Plant in Service	
Intangible Plant	5,792,701.67
Production Plant	1,153,936.87
Transmission Plant	1,204,191.69
Distribution Plant	-
General Plant	-
Total Electric Plant in Service	8,150,830.24
Less: Accumulated Depreciation	255,293.93
Less: Amortization of Other Plant	4,467,689.04
Net Electric Plant in Service	3,427,847.27
Less: Customer Adv for Construction	-
Less: Accumulated Deferred Income Taxes	389,960.98
Add: Plant Held for Future Use	-
Add: Working Capital	-
Add: Other Deferred Amounts	-
Add: Subsidiary Rate Base	
TOTAL COMBINED RATE BASE	3,037,886.29
NET INCOME	
Operating Revenues	
Sales Revenues	-
Other Operating Revenues	-
Total Operating Revenues	-
Operating Expenses	
Operation and Maintenance Expenses	186,458.36
Depreciation Expenses	5,498.98
Amortization of Limited Term Plant	34,966.55
Taxes Other Than Income	3,429.02
Regulatory Debits/Credits	
Provision for Deferred Income Taxes	(5,277.88)
Investment Tax Credit Adjustment	-
Federal Income Taxes	(44,428.32)
State Income Taxes	(13,504.05)
Total Operating Expenses	167,142.66
Operating Income	(167,142.66)
Add: IERCO Operating Income	-
Consolidated Operating Income	(167,142.66)
Rate of Return as filed	(0.06)

Annual Authorized Rate of Return	0.08
Earnings Impact	187,040.81
Net-to-Gross Tax Multiplier	1.35
Monthly Revenue Requirement	**251,872.90**

Components of Monthly Revenue Requirement

Return on Rate Base	19,898.16
Gross-up factor	1.35
Total Monthly Rev Req for Return on Rate Base	**26,795.25**
Start-up Costs Amortization	-
Gross-up factor	1.35
Total Monthly Rev Req for Start-Up Costs	**-**
Other Operating Expense	167,142.66
Gross-up factor	1.35
Total Monthly Rev Req for Other Operating Exp	**225,077.65**
Total Monthly Revenue Requirement	**251,872.90**

Idaho Power Company
Western EIM Participation Costs
Idaho Jurisdictional Revenue Requirement

RATE BASE	
Electric Plant in Service	
Intangible Plant	5,792,701.67
Production Plant	1,153,936.87
Transmission Plant	1,204,191.69
Distribution Plant	-
General Plant	-
Total Electric Plant in Service	8,150,830.24
Less: Accumulated Depreciation	260,792.90
Less: Amortization of Other Plant	4,502,655.59
Net Electric Plant in Service	3,387,381.75
Less: Customer Adv for Construction	-
Less: Accumulated Deferred Income Taxes	428,957.08
Add: Plant Held for Future Use	-
Add: Working Capital	-
Add: Other Deferred Amounts	-
Add: Subsidiary Rate Base	
TOTAL COMBINED RATE BASE	2,958,424.67
NET INCOME	
Operating Revenues	
Sales Revenues	-
Other Operating Revenues	-
Total Operating Revenues	-
Operating Expenses	
Operation and Maintenance Expenses	156,674.85
Depreciation Expenses	5,498.98
Amortization of Limited Term Plant	34,966.55
Taxes Other Than Income	3,429.02
Regulatory Debits/Credits	
Provision for Deferred Income Taxes	(5,277.88)
Investment Tax Credit Adjustment	-
Federal Income Taxes	(38,549.05)
State Income Taxes	(11,717.04)
Total Operating Expenses	145,025.44
Operating Income	(145,025.44)
Add: IERCO Operating Income	-
Consolidated Operating Income	(145,025.44)
Rate of Return as filed	(0.05)

Annual Authorized Rate of Return	0.08
Earnings Impact	164,403.12
Net-to-Gross Tax Multiplier	1.35
Monthly Revenue Requirement	**221,388.53**

Components of Monthly Revenue Requirement

Return on Rate Base	19,377.68
Gross-up factor	1.35
Total Monthly Rev Req for Return on Rate Base	**26,094.37**
Start-up Costs Amortization	-
Gross-up factor	1.35
Total Monthly Rev Req for Start-Up Costs	**-**
Other Operating Expense	145,025.44
Gross-up factor	1.35
Total Monthly Rev Req for Other Operating Exp	**195,294.16**
Total Monthly Revenue Requirement	**221,388.53**

Idaho Power Company
Western EIM Participation Costs
Idaho Jurisdictional Revenue Requirement

RATE BASE	**Mar-23**
Electric Plant in Service	
Intangible Plant	$ 5,792,702
Production Plant	1,153,937
Transmission Plant	1,204,192
Distribution Plant	-
General Plant	-
Total Electric Plant in Service	8,150,830
Less: Accumulated Depreciation	266,292
Less: Amortization of Other Plant	4,537,622
Net Electric Plant in Service	3,346,916
Less: Customer Adv for Construction	-
Less: Accumulated Deferred Income Taxes	467,953
Add: Plant Held for Future Use	-
Add: Working Capital	-
Add: Other Deferred Amounts	-
Add: Subsidiary Rate Base	
TOTAL COMBINED RATE BASE	2,878,963

NET INCOME	
Operating Revenues	
Sales Revenues	-
Other Operating Revenues	-
Total Operating Revenues	-
Operating Expenses	
Operation and Maintenance Expenses	176,216
Depreciation Expenses	5,499
Amortization of Limited Term Plant	34,967
Taxes Other Than Income	3,429
Regulatory Debits/Credits	
Provision for Deferred Income Taxes	(5,278)
Investment Tax Credit Adjustment	-
Federal Income Taxes	(42,407)
State Income Taxes	(12,890)
Total Operating Expenses	159,537
Operating Income	(159,537)
Add: IERCO Operating Income	-
Consolidated Operating Income	(159,537)
Rate of Return as filed	(0)

Annual Authorized Rate of Return	0
Earnings Impact	178,394
Net-to-Gross Tax Multiplier	1
Monthly Revenue Requirement	**240,229**

Components of Monthly Revenue Requirement

Return on Rate Base	$	18,857
Gross-up factor		1.347
Total Monthly Rev Req for Return on Rate Base		**25,393**
Start-up Costs Amortization		0
Gross-up factor		1.347
Total Monthly Rev Req for Start-Up Costs		**0**
Other Operating Expense		159,537
Gross-up factor		1.347
Total Monthly Rev Req for Other Operating Exp		**214,836**
Total Monthly Revenue Requirement	**$**	**240,229**

Power Cost Adjustment Calendar Month Accrual Calculations

				2015-2019	2020 Total	2021 Total	2022 Total	2023												Total
				Cumulative Total				January	February	March	April	May	June	July	August	September	October	November	December	**All Years**
Sales Based Adjustment	*Prior*	*New (Effective 6/1/15)*																		
Actual Idaho Jurisdictional ***Calendar*** Month Sales			Mwh	68,807,570	14,160,172	14,720,217	15,127,055	1,255,296	1,120,338	1,156,785										
Normalized Idaho Jurisdictional ***Calendar*** Month Sales			Mwh	67,494,460	13,498,892	13,498,892	13,498,892	1,169,255	990,343	981,891	0	0	0	0	0	0	0	0	0	107,991,136
Sales Change			Mwh	1,313,110	661,280	1,221,325	1,628,163	86,041	129,995	174,894	0	0	0	0	0	0	0	0	0	(107,991,136)
% of Prior Period Billings at Old Rate								0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
% of Current Period Billings at New Rate								100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	
Sales Adjustment Prior To Sharing @		$ 26.72	$	(35,086,299.20)	(17,669,401.60)	(32,633,804.00)	(43,504,509.03)	(2,299,003.13)	(3,473,460.32)	(4,673,164.93)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(128,894,013.83)
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%	
Calendar Month Sales Based Adjustment			$	(33,331,984.24)	(16,785,931.52)	(31,002,113.81)	(41,329,283.58)	(2,184,052.97)	(3,299,787.30)	(4,439,506.68)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(122,449,313.15)
Billing Month Sales Based Adjustment (from PCA Worksheet)			$	(31,321,930.20)	(15,344,094.93)	(31,319,972.25)	(40,271,037.70)	(2,327,687.42)	(3,053,060.60)	(4,171,704.25)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(118,257,035.08)
Net Calendar Month Deferral / Accrual			$	(2,010,054.04)	(1,441,836.59)	317,858.44	(1,058,245.88)	143,634.45	(246,726.70)	(267,802.43)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(4,192,278.07)
Accounting:								*Dr (Cr)*	*Dr (Cr)*	*Dr (Cr)*	*Dr (Cr)*	*Dr (Cr)*	*Dr (Cr)*	*Dr (Cr)*	*Dr (Cr)*	*Dr (Cr)*	*Dr (Cr)*	*Dr (Cr)*	*Dr (Cr)*	*Dr (Cr)*
799 X00001 999 182326				(2,010,054.04)	(1,441,836.59)	317,858.44	(1,058,245.88)	143,634.45	(246,726.70)	(267,802.43)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(4,563,172.75)
693 M30108 441 557001				2,010,054.04	1,441,836.59	(317,858.44)	1,058,245.88	(143,634.45)	246,726.70	267,802.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4,563,172.75

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-12

IDAHO POWER COMPANY

BRADY, DI
TESTIMONY

EXHIBIT NO. 3

IDAHO POWER COMPANY

ADDITIONAL INVESTMENT TAX CREDIT ANALYSIS
For the Twelve Months Ended December 31, 2022

Line		Actual September 30, 2022			Actual December 31, 2022		
7-8		TOTAL SYSTEM	IDAHO	IDAHO %	TOTAL SYSTEM	IDAHO	IDAHO %
9	*** * * SUMMARY OF RESULTS * * ****						
10	TOTAL COMBINED RATE BASE	3,816,760,459	3,659,529,896	95.881%	September Allocations/Ratios		
11							
12	DEVELOPMENT OF NET INCOME						
13	OPERATING REVENUES						
14	RETAIL SALES REVENUES (Incl 449.1 Rev)	1,048,578,872	1,003,074,365	Direct Assign	1,372,758,056	1,312,548,812	Direct Assign
15	OTHER OPERATING REVENUES	167,118,182	160,109,387	95.8%	264,369,926	253,282,475	95.8%
16	TOTAL OPERATING REVENUES	1,215,697,054	1,163,183,751		1,637,127,982	1,565,831,287	
17							
18	OPERATING EXPENSES						
19	OPERATION & MAINTENANCE EXPENSES	793,265,607	755,302,382	95.2%	1,105,868,787	1,052,945,345	95.2%
20	DEPRECIATION EXPENSE	120,425,620	115,582,841	96.0%	163,581,418	157,003,177	96.0%
21	AMORTIZATION OF LIMITED TERM PLANT	3,510,742	3,369,427	96.0%	4,852,904	4,657,563	96.0%
22	TAXES OTHER THAN INCOME	25,015,497	23,226,349	92.8%	28,701,676	26,648,887	92.8%
23	REGULATORY DEBITS/CREDITS	1,249,451	1,022,156	81.8%	1,753,318	1,434,363	81.8%
24	PROVISION FOR DEFERRED INCOME TAXES	(7,519,188)	(7,114,821)	94.6%	(10,828,285)	(10,245,961)	94.6%
25	INVESTMENT TAX CREDIT ADJUSTMENT	3,334,345	3,199,107	95.9%	5,825,740	5,589,454	95.9%
26	FEDERAL INCOME TAXES	26,089,683	25,397,531	97.3%	42,187,659	41,068,433	97.3%
27	STATE INCOME TAXES	9,757,987	9,513,728	97.5%	1,940,619	1,892,042	97.5%
28	TOTAL OPERATING EXPENSES	975,129,745	929,498,701		1,343,883,837	1,280,993,303	
29							
30	OPERATING INCOME	240,567,309	233,685,051		293,244,145	284,837,983	
31	ADD: IERCO OPERATING INCOME	6,559,424	6,269,611	95.6%	8,782,042	8,394,028	95.6%
32							
33	OPERATING INCOME BEFORE OTHER INCOME AND DEDUCTION:	247,126,732	239,954,662		302,026,187	293,232,011	97.1%
34	ADD: AFUDC EQUITY				37,285,494	35,749,526	95.9% (L 10)
35	ADD: OTHER INCOME AND DEDUCTIONS				4,596,024	4,462,201	97.1% (L 33)
36							
37	INCOME BEFORE INTEREST CHARGES				343,907,704	333,443,738	
38	LESS: INTEREST CHARGES				89,041,036	85,373,011	95.9% (L 10)
39							
40	NET INCOME				254,866,668	248,070,726	
41							
42	ACTUAL YEAR-END RESULTS - BEFORE ITC ADJUSTMENT						
43	EARNINGS ON COMMON STOCK				254,866,668	248,070,726	
44	COMMON EQUITY AT YEAR END				2,631,661,816	2,523,251,118	95.9% (L10)
45							
46	RETURN ON YEAR-END COMMON EQUITY				9.68%	9.83%	
47							
48	EARNINGS ON COMMON STOCK @ 9.40 ROE				250,007,873	**237,185,605**	(L44 * 9.4%)
49	EARNINGS ON COMMON STOCK @ 10 ROE				263,166,182	**252,325,112**	(L44 * 10%)
50	EARNINGS ON COMMON STOCK @ 10.50 ROE				276,324,491	**264,941,367**	(L44 * 10.5%)
51							
52							
53	ACTUAL YEAR-END RESULTS - AFTER ITC ADJUSTMENT:						
54	INVESTMENT TAX CREDIT ADJUSTMENT					(12,014,483)	(L48-L43) / (1-9.4%)
55	ADJUSTED EARNINGS ON COMMON STOCK					236,056,244	
56	ADJUSTED COMMON EQUITY AT YEAR-END					2,511,236,635	
57	ADJUSTED RETURN ON YEAR-END COMMON EQUITY					9.40%	
58							
59	**IF IDAHO RETURN ON COMMON EQUITY (Line 46) <9.4%**						
60	ADDITIONAL ITC ADJUSTMENT (Annualized)	If L 54 is negative, then 0; if positive, then smaller of L54 or $25,000,000				0	
61							
62	**IF IDAHO RETURN ON COMMON EQUITY (Line 46) >10%**						
63	IDAHO EARNINGS GREATER THAN 10% ROE BUT LESS THAN 10.5%					0	(L43-L49)/(1-10%)
64							
65	**IF IDAHO RETURN ON COMMON EQUITY (Line 46) >10.5%**						
66	INCREMENTAL IDAHO EARNINGS GREATER THAN 10.50% ROE					0	(L43-L50)/(1-10.5%)
67							
68	**Per Order #34071:**					After Tax	Tax Gross Up
69	ROE between 10%-10.5% --CUSTOMER SHARE - 80% (Reduction to rates)					0	-
70	ROE between 10%-10.5% --COMPANY SHARE - 20%					0	
71	ROE greater than 10.5% (Incremental) -- CUSTOMER SHARE - 55% (Reduction to rates)					0	-
	ROE greater than 10.5% (Incremental) -- CUSTOMER SHARE - 25% (Offset to Pension balance)					0	-
72	ROE greater than 10.5% (Incremental) --COMPANY SHARE - 20%					0	
73						0	
74							

Prepared by: Kelley Noe

Reviewed by: ______________________

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-12

IDAHO POWER COMPANY

CONFIDENTIAL

BRADY, DI
TESTIMONY

EXHIBIT NO. 4