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, 2015, THROUGH MAY 31, 2016.	CASE NO. IPC-E-15-14

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

SCOTT WRIGHT

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

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

Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Business Economics from Eastern Oregon University. I have also attended the Center for Public Utilities "Practical Skills for a Changing Electric Industry" a course offered through New Mexico State University in Albuquerque, New Mexico, the Edison Electric Institute's "Electric Rate Advanced Course" in Madison, Wisconsin, the NERA "Marginal Costing for Electric Utilities", in Los Angeles, California, and the Financial Accounting Institute "Utility Finance and Accounting Course" in Las Vegas, Nevada.

Q. Please describe your work experience with Idaho Power.

A. In May 1998, I accepted a position as Research Assistant with Idaho Power in the Regulatory Affairs Department. In March 2007, I was promoted to a Regulatory Analyst. In March 2010, I was promoted to a Regulatory Analyst II. As a Regulatory Analyst II, I am responsible for running the AURORA model to calculate Net Power Supply Expenses ("NPSE") for ratemaking purposes, preparing the Power Cost Adjustment filings in Idaho and Oregon, as well as the marginal cost of energy used in the Company's marginal cost analysis. I also provide analytical support for other regulatory activities within the Regulatory Affairs Department, as well as providing testimony in other Company filings.

Q. What is the Company requesting in this case?

A. The Company is requesting approval of its quantification of the 2015-2016 PCA rates to become effective June 1, 2015. If approved, the 2015-2016 PCA will result in a revenue decrease of approximately $10.1 million, or a 0.91 percent.

Q. How is the Company's case organized?

A. The Company's case includes testimony and exhibits from two witnesses. My testimony provides an overview of the PCA, describes the determination of the 2015-2016 PCA amount, identifies and explains the main factors contributing to this year's PCA amount, and presents the quantification of the 2015-2016 PCA rates. Kelley K. Noe provides testimony that describes the quantification of the revenue sharing amount to be included in this year's PCA.

I. **OVERVIEW OF PCA COMPONENTS**

Q. What is the purpose of the PCA and how does the mechanism function?

A. The PCA is a rate mechanism that quantifies and tracks annual differences between actual NPSE and the normalized or "base level" of NPSE recovered in the Company's base rates for recovery or credit through an annual rate change on June 1. The PCA mechanism utilizes a 12-month test period of April through March ("PCA Year") and is comprised of a forecast component and a PCA True-Up component. The PCA forecast component is based on the Company's March Operating Plan and represents the difference between the NPSE forecast from the March Operating Plan and the base level NPSE recovered in the Company's base rates. The PCA True-Up includes a backward looking tracking of differences between the prior year's forecast and actual NPSE incurred by the Company during the prior PCA year. The PCA True-Up contains a second component that tracks the collection of the prior year's true-up amount, referred to as the "True-Up of the True-Up."

With the exception of Public Utility Regulatory Policies Act of 1978 ("PURPA") expenses and demand response incentive costs, the PCA allows the Company to pass through to customers 95 percent of the annual differences in actual

NPSE as compared to the base level NPSE, whether positive or negative. The PCA is also the rate mechanism used by the Company to provide direct revenue sharing benefits resulting from the revenue sharing mechanism approved by Order No. 32424.

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

A. The PCA base level NPSE include the following Federal Energy Regulatory Commission ("FERC") accounts: FERC Account 501, fuel (coal); FERC Account 536, water for power; FERC Account 547, fuel (gas); FERC Account 555, purchased power; FERC Account 565, transmission of electricity by others; and FERC Account 447, sales for resale (typically referred to as surplus sales).

The PCA base level expense component for FERC Account 555 includes both power purchases resulting from PURPA and non-PURPA (market) purchases. As per Order No. 32426, the Company adjusts FERC Account 555 to include demand response incentive payments that the Company provides to customers for participating in any of its three demand response programs.

II. 2015-2016 PCA

Q. What is the total 2015-2016 PCA amount as measured from the currently approved base level NPSE?

A. Approved on March, 21, 2014, Order No. 33000 authorized Idaho Power's current base level NPSE. The 2015-2016 total PCA amount (including revenue sharing and a $4.0 million DSM Rider adjustment) as measured from the currently approved base level NPSE is $63.1 million. This represents a decrease in total billed revenue of $10.1 million for the upcoming year, a reduction of 0.91 percent.

PCA Forecast

Q. What is the Company's determination of the system-level difference between the currently approved base level NPSE and the forecast of NPSE for the 2015-2016 PCA Year?

A. The system-level forecast of NPSE for the 2015-2016 PCA Year is for $348,384,126, which is $42,699,257 higher than the currently approved base level NPSE of $305,684,869. The following Table 1 presents the system-level differences between the currently approved base level NPSE and the forecast of NPSE for the 2015-2016 PCA Year by each NPSE category.

Table 1:	2015-2016 PCA FORECAST (Total System)			
Line No.	FERC Account	Base NPSE	Forecast	Difference
	95% Sharing Accounts			
1.	Account 501, Coal	$ 108,503,180	$ 117,032,475	$ 8,529,295
2.	Account 536, Water for Power	$ 2,380,597	$ 2,425,230	$ 44,633
3.	Account 547, Other Fuel	$ 33,367,563	$ 57,173,815	$ 23,806,252
4.	Account 555, Purchased Power Non-PURPA	$ 62,606,593	$ 48,372,214	$ (14,234,379)
5.	Account 565, 3rd Party Transmission	$ 5,455,955	$ 6,453,427	$ 997,472
6.	Account 447, Surplus Sales	$ (51,735,153)	$ (39,048,702)	$ 12,686,451
		$ 160,578,735	$ 192,408,459	$ 31,829,724
	100% Sharing Accounts			
7.	Account 555, PURPA	$ 133,853,869	$ 148,054,626	$ 14,200,757
8.	Account 555, Demand Response Incentives	$ 11,252,265	$ 7,921,041	$ (3,331,224)
9.	Total	$ 305,684,869	$ 348,384,126	$ 42,699,257

Q. What is the basis for the forecast of NPSE for the 2015-2016 PCA Year?

A. The forecast of NPSE for the 2015-2016 PCA Year is based upon the Company's March 26, 2015, Operating Plan ("Operating Plan").

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

A. The Company's Operating Plan is produced monthly and forecasts 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 economic 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. Economically dispatched generation above the system load forecast represents surplus energy sales.

Q. How does the Company's forecast of NPSE for the 2015-2016 PCA compare to the forecast in last year's PCA?

A. As can be seen on Table 2, the PCA forecast on a total forecast system basis for the 2015-2016 PCA is expected to be $348,384,126, which is $18,357,870 higher than last year's forecast amount of $330,026,256.

Table 2:	**PCA Forecast Comparison Expenses (Total System)**			
Line No.	**FERC Account**	**2014-2015 Forecast**	**2015-2016 Forecast**	**Difference**
	95 % Sharing Accounts			
1.	Account 501, Coal	$ 169,424,879	$ 117,032,475	$ (52,392,404)
2.	Account 536, Water for Power	$ 1,751,000	$ 2,425,230	$ 674,230
3.	Account 547, Other Fuel	$ 73,941,673	$ 57,173,815	$ (16,767,858)
4.	Account 555, Purchased Power Non-PURPA	$ 61,996,853	$ 48,372,214	$ (13,624,639)
5.	Account 565, 3rd Party Transmission	$ 6,645,775	$ 6,453,427	$ (192,348)
6.	Account 447, Surplus Sales	$ (126,166,913)	$ (39,048,702)	$ 87,118,211
		$ 187,593,267	$ 192,408,459	$ 4,815,192
	100% Sharing Accounts			
7.	Account 555, PURPA	$ 134,142,386	$ 148,054,626	$ 13,912,240
8.	Account 555, Demand Response Incentive	$ 8,290,603	$ 7,921,041	$ (369,562)
		$ 142,432,989	$ 155,975,667	$ 13,542,678
9.	Total PCA Forecast	$ 330,026,256	$ 348,384,126	$ 18,357,870

Q. What conclusions can be drawn from the information contained in Table 2?

A. Table 2 compares this year's 2015-2016 PCA forecast to last year's PCA forecast for each NPSE category. As can be seen on Table 2, the 95 percent sharing accounts represent an increase of $4.8 million and the 100 percent sharing accounts represent an increase of $13.5 million over last year's 2014-2015 PCA forecast.

Q. What factors do you believe contributed to the major differences presented on Table 2?

A. Lower market energy prices have driven down the Company's expectation of surplus sales revenue by 69 percent as compared to last year's forecast. The reduction in surplus sales revenue is, however, largely offset by the reductions in coal and gas production costs and lower Non-PURPA market energy purchases. Increases in PURPA costs account for approximately 76 percent or $13.9 million of the year-over-year increase in this year's PCA forecast.

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

A. No. The increase in PURPA expense is largely the result of a higher per-unit cost, not volumes. As can be seen on the following Table 3, PURPA generation output is anticipated to increase by only 131 thousand megawatt-hours ("MWh"), or 6 percent, as compared to last year's PCA forecast. The majority of the 76 percent increase in PURPA-related costs can be attributed to price escalation in PURPA contracts and updated production curves based on newly available historical operational data.

Table 3:	PCA Forecast Comparison Generation (Total System-MWh)			
Line No.	FERC Account	2014-2015 Forecast	2015-2016 Forecast	Difference
1.	Hydro	6,912,870	8,132,991	1,220,121
	95% Sharing Accounts			
2.	Account 501, Coal	6,529,271	3,953,060	(2,576,212)
3.	Account 547, Other Fuel	2,114,121	2,297,609	183,488
4.	Account 555, Purchased Power Non-PURPA	1,345,589	858,438	(487,151)
		16,901,852	15,242,098	(1,659,754)
	100% Sharing Accounts			
5.	Account 555, PURPA	2,067,959	2,199,216	131,257
	100% Accounts	2,067,959	2,199,216	131,257
6.	Total Generation	18,969,811	17,441,314	(1,528,497)
	95% Sharing Accounts			
8.	Account 447, Surplus Sales	3,397,321	1,651,264	(1,746,057)
9.	Total Load	15,572,490	15,790,050	217,560

Q. What else can be concluded from the information in Table 3?

A. The first item of note in Table 3 is the additional hydro generation of 1.2 million MWh over last year's PCA forecast. The April-July Brownlee Reservoir inflow forecast for this year's PCA forecast is 4.5 million acre feet ("MAF"), as compared to last years forecast of 3.6 MAF for the same months. The 30-year average April-July Brownlee Reservoir inflow is 5.5 MAF, 1.0 MAF above this year's forecast. The additional forecasted streamflows for this year's PCA forecast over last year's PCA forecast is expected to increase hydro generation by 18 percent.

Surplus sales volumes are expected to decrease by 51 percent or 1.7 million MWh from last year, resulting from the lower market prices that were mentioned earlier in my testimony. The combination of additional hydro generation of 1.2 million MWh and reduced surplus sales volumes of 1.7 million MWh is expected to reduce coal generation by 39 percent or 2.6 million MWh from last year's PCA forecast, which is very close to the combined increase in hydro generation and the reduction in surplus sales.

Q. How are the forecasted NPSE differences presented in Table 1 used to determine the 2015-2016 PCA forecast component to be collected from Idaho customers?

A. The 2015-2016 PCA forecast component is represented by the Idaho jurisdictional share of the forecasted NPSE differences presented in Table 1, 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, adjusted for sharing.

Q. What is the Company's forecast of system-level firm sales and Idaho jurisdictional firm sales for the 2015-2016 PCA Year?

A. For the 2015-2016 PCA Year, Idaho Power has forecast system-level firm sales to be 14,545,294 MWh and

Idaho jurisdictional firm sales to be 13,901,424 MWh or 95.57 percent of the system-level.

Q. What is the Company's determination of the 2015-2016 PCA forecast component to be collected from Idaho customers?

A. The 2015-2016 PCA forecast component that is expected to be collected from Idaho customers is $39,140,610. Table 4 presents the determination of the 2015-2016 PCA forecast component by individual PCA expense and revenue category.

Table 4:	2015-2016 PCA FORECAST			
Line No.	FERC Account	Difference from Base	Difference After Sharing	Idaho Allocation
	95% Sharing Accounts	(From Table 1)		
1.	Account 501, Coal	$ 8,529,295	$ 8,102,830	$ 7,744,146
2.	Account 536, Water for Power	$ 44,633	$ 42,401	$ 40,524
3.	Account 547, Other Fuel	$ 23,806,252	$ 22,615,940	$ 21,614,810
4.	Account 555, Purchased Power Non-PURPA	$ (14,234,379)	$ (13,522,660)	$ (12,924,058)
5.	Account 565, 3rd Party Transmission	$ 997,472	$ 947,598	$ 905,651
6.	Account 447, Surplus Sales	$ 12,686,451	$ 12,052,128	$ 11,518,622
		$ 31,829,724	$ 30,238,238	$ 28,899,696
	100% Sharing Accounts			
7.	Account 555, PURPA	$ 14,200,757	$ 14,200,757	$ 13,572,138
8.	Account 555, Demand Response Incentives	$ (3,331,224)	N/A	$ (3,331,224)
9.	Total	$ 42,699,257	$ 44,438,995	$ 39,140,610

True-Up and True-up of the True-Up

Q. What is this year's quantification of the True-Up?

A. The True-Up portion of the PCA is detailed on the deferral expense report, attached as Exhibit No. 1. This report compares actual PCA account results to last year's PCA account projections on a monthly basis, with the differences accumulated as the deferral balance. The balance at the end of March 2015, with interest applied, was $34,515,981, as shown on row 90 of Exhibit No. 1. The approximately $34.5 million represents a charge to customers in this year's PCA.

Q. To what factors do you attribute the accumulation of the approximately $34.5 million deferral balance?

A. The $34.5 million deferral balance was largely driven by lower than forecast market energy prices resulting in lower surplus sales volumes. Actual surplus sales volumes were approximately 43 percent lower than forecasted in last year's PCA. As a result, the Company experienced lower than expected surplus sales revenue, which serves to offset power supply expense.

Actual hydro generation was approximately 7 percent lower than forecast. The April-July Brownlee Reservoir inflows for 2014 were 3.4 MAF, 0.2 MAF below last year's forecast. Lower than forecasted hydro generation also contributed to this year's True-Up.

Q. What is this year's True-Up of the True-Up?

A. The Company under collected last year's PCA True-Up Balance by $1,484,515 as shown on row 110 of the deferral expense report.

Q. What is the combined effect of the True-Up and the True-Up of the True-Up in this year's PCA?

A. The sum of the $34,515,981 associated with the True-Up and the $1,484,515 associated with the True-Up of the True-Up represents $36,000,496 of additional collection from customers. This additional cost in large part reflects that actual net power supply expenses for the 2014-2015 PCA year were greater than the forecast.

Q. How does this year's combined True-Up and the True-Up of the True-Up compare to last year's amount?

A. The combined True-Up and the True-Up of the True-Up for the last PCA Year was $77,229,793 as compared to the this year's amount of $36,000,496, a decrease of $41,229,297.

Q. Why is the total combined True-Up a decrease of approximately $41.2 million over last year's combined PCA True-Up?

A. Even though the 2014-2015 combined PCA True-Up was a positive value, it is still a decrease of approximately $41.2 million over the 2013-2014 combined PCA True-Up balance because the forecast for the 2014-2015 PCA was more accurate than the previous year's forecast for the 2013-2014 PCA.

Other PCA Adjustments

Q. What is the revenue sharing amount for this 2015-2016 PCA Year?

A. Based on the quantification described by Ms. Noe in her testimony, the revenue sharing benefit to be credited to customers in this year's PCA is $7,999,145.

Q. Are there any other recommended adjustments to this year's PCA?

A. Yes. The Company proposes the continued application of a PCA credit related to the Demand-Side Management ("DSM") Rider in the amount of $3,970,036.

Q. Why is this credit necessary?

A. This credit is necessary to maintain the revenue neutrality associated with the 2014 update to the normalized level of NPSE included in base rates approved by Order No. 33000. Idaho Power's current level of DSM Rider collection is four percent of base rate revenues. The approval to increase the Company's level of base rate revenues by $99.3 million effective June 1, 2014, resulted in approximately $4.0 million per year of additional DSM Rider funds. To ensure the base rate increase associated with the new base level of NPSE approved in Case No. IPC-E-13-20 is revenue neutral for all classes of customers, it is appropriate to offset the increase in DSM Rider revenue by moving $4.0 million out of the DSM Rider balancing account and providing that amount as a credit to customers in the 2015-2016 PCA. This adjustment should continue to be included in PCA rate determinations until the level of NPSE recovery in base rates is re-established as part of a general rate case or otherwise adjusted by Commission order.

III. PCA RATE DETERMINATION

Q. How is the rate for the forecast portion of the PCA for April 2015 through March 2016 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 power supply expenses, divided by the Company's normalized system firm sales, 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 power supply expenses, divided by the Company's normalized system firm sales, 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 power supply expenses, divided by the Idaho jurisdictional sales.

Q. What is the rate for the forecast portion of the PCA for April 2015 through March 2016?

The rate for non-PURPA expenses is 0.2079 cents per kilowatt-hour ("kWh"), which is calculated by multiplying $31,829,724 from Table 1 by 95 percent and then dividing it by the normalized system firm sales of 14,545,294 MWh (($31,829,724 * 0.95) / 14,545,294) = $2.08/MWh = 0.2079 cents/kWh). The rate for PURPA expenses is 0.0976 cents per kWh, which is calculated by dividing $14,200,757 from Table 1 by the 14,545,294 MWh ($14,200,757 / 14,545,294 MWh = $0.98/MWh = 0.0976 cents/kWh). The rate for the demand response incentive payment is a negative 0.0240 cents per kWh, which is calculated by dividing a negative $3,331,224 from Table 1 by the Idaho jurisdictional firm sales of 13,901,424 MWh (-$3,331,224 / 13,901,424 MWh = -$0.24/MWh = -0.0240 cents/kWh). The forecast portion of the PCA rate is 0.2815 cents per kWh, which is calculated by adding the non-PURPA expense of 0.2079 cents per kWh to the PURPA expense of 0.0976 cents per kWh to the demand response incentive payment of negative 0.0240 cents per kWh (0.2079 + 0.0976 + -0.0240 = 0.2815 cents/kWh).

Q. How did you compute this year's True-Up rate?

A. As shown in Exhibit No. 1, this year's True-Up component of the PCA is $34.5 million, which when divided by the Company's forecast of Idaho jurisdictional sales of

13,901,424 MWh results in a rate of 0.2483 cents per kWh ($34.5 million / 13,901,424 = $2.48/MWh = 0.2483 cents/kWh).

The True-Up of the True-Up rate is calculated by dividing $1.5 million (also from Exhibit No. 1) by the forecast of Idaho jurisdictional sales of 13,901,424 MWh, which results in a rate of 0.0107 cents per kWh ($1.5 million / 13,901,424 = $0.11/MWh = 0.0107 cents/kWh).

Q. Does the quantified True-Up rate include the sales of Renewable Energy Certificates ("RECs") and Sulfur Dioxide ("SO_2") proceeds?

A. Yes. The RECs and SO_2 proceeds are included in the Company's deferral expense report, provided as Exhibit No. 1 on lines 37 and 38. Order No. 32002 issued on June 11, 2010, approved the Company's REC Management Plan, which passes the customers' share of REC benefits back to the customer through the PCA. Order No. 32434 approved on January 12, 2012, directed the Company to pass SO_2 proceeds through the PCA to help offset the Company's PCA deferral balance.

Q. How has the Company determined the PCA rate credits associated with revenue sharing and the DSM Rider transfer?

A. All classes of customers will receive revenue sharing benefits in the form of a volumetric rate with the exception of the special contract customers who will receive this benefit in the form of 12 equal monthly bill credits. The adjustment related to the DSM Rider will be provided as a uniform rate credit. This approach will allow each customer class to receive the credit in the same proportion as their respective increase in base rates. The adjustment related to the DSM Rider will be provided in the form of a volumetric rate for all classes of customers. Exhibit No. 2, columns A and B show the annual revenue sharing benefits and the adjustment related to the DSM Rider for all classes of customers. Columns C and D show the cents per kWh rate for the classes that will receive revenue sharing benefits and the adjustment related to the DSM Rider in the form of a volumetric rate.

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

A. The Company's PCA rate for the 2015-2016 PCA year is detailed in Exhibit No. 2, column E. The uniform PCA rate is comprised of (1) the 0.2815 cents per kWh adjustment for the 2015-2016 projected power cost of serving firm loads, under the current PCA methodology and 95 percent sharing, (2) the 0.2483 cents per kWh for the 2014-2015 True-Up portion of the PCA, and (3) the 0.0107 cents per kWh for the True-Up of the True-Up. The sum of these three components results in a 0.5405 cents per kWh charge for all rate classes.

In addition to the uniform PCA rate, each rate class is assigned a portion of the $8.0 million of revenue sharing and a portion of the $4.0 million for the adjustment related to the DSM Rider. When these amounts are combined with the uniform PCA rate, each class will receive a different PCA rate. The final PCA rates, including revenue sharing and the adjustment related to the DSM Rider are listed by rate schedule in Exhibit No. 2, column F.

Q. What is the revenue impact of the requested PCA rate combined with the revenue sharing rates and the adjustment related to the DSM Rider when compared to the PCA rate currently in effect?

A. Attachment 2 to the Application provides a detailed description of the overall revenue impact of this filing on each customer class. As shown on Attachment 2, applying the requested PCA rates to expected customer loads for the June 2015 through May 2016 test year results in a PCA decrease of $10.1 million.

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

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

Q. Should the Commission approve the Company's computation of the PCA rates?

A. Yes. The Commission should approve the Company's computation of the PCA rates. The calculation of the PCA rates follows the methodology that was approved in Order Nos. 30715, 30978, 32424, 32578, and 33000.

Q. Does this conclude your testimony?

A. Yes, it does.

ATTESTATION OF TESTIMONY

STATE OF IDAHO)
) ss.
County of Ada)

I, Scott Wright, having been duly sworn to testify truthfully, and based upon my personal knowledge, state the following:

I am employed by Idaho Power Company as a Regulatory Analyst II in the Regulatory Affairs Department and am competent to be a witness in this proceeding.

I declare under penalty of perjury of the laws of the state of Idaho that the foregoing pre-filed testimony and exhibits are true and correct to the best of my information and belief.

DATED this 15th day of April, 2015.

____
Scott Wright

SUBSCRIBED AND SWORN to before me this 15th day of April, 2015.

KIMBERLY K. TOWELL
NOTARY
PUBLIC
STATE OF IDAHO

Kimberly K. Towell
Notary Public for Idaho
Residing at: Star, ID
My commission expires: 12-20-2020

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-15-14

IDAHO POWER COMPANY

WRIGHT, DI
TESTIMONY

EXHIBIT NO. 1

Idaho Power Company
PCA Deferral Expense Report
Filed April 15, 2015

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	Power Cost Adjustment														
2	April 2014 thru March 2015		April	May	June	July	August	September	October	November	December	January	February	March	Totals
3															
4	PCA Forecasted Revenues														
5	Actual Idaho Jurisdictional Sales	Mwh	903,276	1,000,008	1,245,883	1,481,996	1,469,408	1,197,549	1,016,641	936,645	1,049,370	1,094,244	1,027,060	925,126	13,347,206
6	PCA Component Rate	$	8.258	8.258	8.258 / 1.609	8.258 / 1.609	1.609	1.609	1.609	1.609	1.609	1.609	1.609	1.609	
7	Forecasted Revenues	$	7,459,253.21	8,258,066.06	6,905,491.09	2,628,859.91	2,364,276.93	1,926,857.08	1,635,775.63	1,507,061.52	1,688,435.91	1,760,639.13	1,652,538.94	1,488,528.34	39,275,783.75
8															
9	Load Change Adjustment														
10	Actual Firm Load	Mwh	1,061,228	1,324,253	1,517,288	1,823,102	1,433,697	1,206,843	1,035,612	1,138,162	1,213,221	1,256,181	999,860	1,054,545	15,063,992
11	Normalized Firm Load	Mwh	1,047,064	1,271,705	1,393,674	1,744,091	1,586,231	1,279,154	1,098,456	1,131,972	1,358,395	1,346,312	1,139,208	1,134,875	15,531,137
12	Load Change	Mwh	14,164	52,548	123,614	79,011	(152,534)	(72,311)	(62,844)	6,190	(145,174)	(90,131)	(139,348)	(80,330)	(467,145)
13	Expense Adjustment ($17.64) Effective 6/1/14 Order 33000 ($24.34)		(249,852.96)	(926,946.72)	(3,008,764.76)	(1,923,127.74)	3,712,677.56	1,760,049.74	1,529,622.96	(150,664.60)	3,533,535.16	2,193,788.54	3,391,730.32	1,955,232.20	11,817,279.70
14															
15	Actual Non-QF PCA														
16	Expense Adjustment	$	(249,852.96)	(926,946.72)	(3,008,764.76)	(1,923,127.74)	3,712,677.56	1,760,049.74	1,529,622.96	(150,664.60)	3,533,535.16	2,193,788.54	3,391,730.32	1,955,232.20	11,817,279.70
17	Fuel Expense-Coal	$	7,933,244.00	10,144,324.71	12,133,812.69	16,630,247.40	15,940,557.42	15,644,237.89	13,811,175.79	10,325,041.27	12,574,620.82	9,366,300.86	6,865,752.08	7,939,580.86	139,308,895.79
18	Fuel Expense-Gas	$	781,718.41	1,274,180.08	2,079,915.33	6,184,049.20	7,029,108.48	5,559,084.00	1,165,048.98	4,367,760.49	2,038,999.99	5,747,656.98	667,179.41	807,845.36	37,702,546.71
19	Non-Firm Purchases	$	5,170,026.94	8,694,579.13	7,791,651.76	11,173,415.32	10,789,558.28	2,858,286.51	4,383,409.27	8,378,696.35	7,669,728.87	4,100,575.38	4,388,957.30	5,771,370.81	81,170,255.92
20	Third Party Transmission	$	329,348.91	409,495.90	557,252.40	839,958.74	721,353.28	910,629.05	637,023.79	370,142.73	314,389.02	315,262.06	308,501.98	333,025.25	6,046,383.11
21	Surplus Sales	$	(5,134,613.49)	(2,669,393.02)	(3,491,506.39)	(1,968,749.32)	(6,959,881.57)	(6,061,171.70)	(6,949,603.80)	(6,938,248.03)	(6,395,431.04)	(4,445,694.29)	(3,398,034.23)	(4,845,158.22)	(59,257,485.10)
22	Hoku 1st Block Energy	$	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Water for Power (Leases)	$	-	-	-	695,250.00	695,250.00	-	-	-	500.00	-	136,000.00	-	1,527,000.00
24	Total Non-QF	$	8,829,871.81	16,926,240.08	16,062,361.03	31,631,043.60	31,928,623.45	20,671,115.49	14,576,676.99	16,352,728.21	19,736,342.82	17,277,889.53	12,360,086.86	11,961,896.26	218,314,876.13
25															
26	BASE														
27	Fuel Expense-Coal	$	11,311,629.00	11,169,485.00	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	8,098,077.00	115,971,408.00
28	Fuel Expense-Gas	$	3,513,672.00	3,469,518.00	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	2,490,370.00	35,733,899.00
29	Non-Firm Purchases	$	3,079,041.00	3,040,349.00	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	60,063,512.00
30	Third Party Transmission	$	558,976.00	551,952.00	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	407,202.00	5,811,977.00
31	Hoku 1st Block Energy	$	(1,618,436.00)	(1,598,098.00)	-	-	-	-	-	-	-	-	-	-	(3,216,534.00)
32	Surplus Sales	$	(8,451,355.00)	(8,345,154.00)	(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)	(3,861,226.00)	(61,373,402.00)
33	Water for Power (Leases)	$	123,719.00	122,164.00	197,883.00	249,796.00	267,352.00	236,886.00	170,727.00	160,216.00	185,506.00	209,613.00	195,554.00	177,675.00	2,297,091.00
34	Net 95% Items	$	8,517,246.00	8,410,216.00	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	13,190,741.00	11,984,708.00	155,287,951.00
35															
36	Change From Base	$	312,625.81	8,516,024.08	2,714,512.03	14,781,493.60	13,894,884.45	4,692,379.49	3,060,570.99	5,545,689.21	7,223,379.82	3,138,831.53	(830,654.14)	(22,811.74)	63,026,925.13
37	Emission Allowance Sales Credit	$	-	-	-	-	(16,250.00)	-	-	-	-	-	-	-	(16,250.00)
38	Renewable Energy Credit Sales	$	(773,052.60)	(68,756.21)	(455,397.32)	(164,364.64)	(69,200.39)	(74,702.65)	8,898.16	1,663.00	(276,848.78)	(10,154.28)	(519,360.23)	789.33	(2,400,486.61)
39	Subtotal	$	(460,426.79)	8,447,267.87	2,259,114.71	14,617,128.96	13,809,434.06	4,617,676.84	3,069,469.15	5,547,352.21	6,946,531.04	3,128,677.25	(1,350,014.37)	(22,022.41)	60,610,188.52
40															
41	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%	
42	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%	
43															
44	Net Power Supply Costs Deferral	$	(415,535.18)	7,623,659.25	2,038,851.03	13,191,958.89	12,463,014.24	4,167,453.35	2,770,195.91	5,006,485.37	6,269,244.26	2,823,631.22	(1,218,387.97)	(19,875.23)	54,700,695.14
45															
46	Demand Response Incentive Payments														
47	Actual	$	(1.00)	-	615,101.57	3,010,208.98	3,521,645.81	698,160.63	23,478.95	2,108.60	75,873.84	-	-	150.54	7,946,727.92
48	Base	$	761,286.00	751,719.00	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	11,208,367.00
49	Change From Base	$	(761,287.00)	(751,719.00)	(320,225.43)	1,829,506.98	2,257,963.81	(421,520.37)	(783,491.05)	(755,175.40)	(800,949.16)	(990,769.00)	(924,317.00)	(839,656.46)	(3,261,639.08)
50															
51	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%	
52	Idaho Allocation		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
53															
54	Demand Response Incentive Payment Deferral	$	(761,287.00)	(751,719.00)	(320,225.43)	1,829,506.98	2,257,963.81	(421,520.37)	(783,491.05)	(755,175.40)	(800,949.16)	(990,769.00)	(924,317.00)	(839,656.46)	(3,261,639.08)
55															
56															
57	Actual QF (Includes Net Metering, Raft River 100% & Liquidated Damages)	$	11,678,111.71	10,818,854.67	16,372,587.92	13,753,153.64	12,665,482.93	12,725,603.89	12,470,079.82	13,697,371.84	15,313,405.96	7,437,925.81	11,356,809.93	8,815,962.34	147,105,350.46
58	Base QF	$	4,252,292.00	4,198,857.00	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	123,784,522.00
59	Change From Base	$	7,425,819.71	6,619,997.67	5,246,199.92	(292,153.36)	(2,366,930.07)	(593,816.11)	2,870,581.82	4,688,931.84	4,882,955.96	(4,347,991.19)	361,382.93	(1,174,150.66)	23,320,828.46
60															
61	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%	
62	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%	
63															
64	QF Deferral	$	7,054,528.72	6,288,997.79	4,983,889.92	(277,545.69)	(2,248,583.57)	(564,125.30)	2,727,052.73	4,454,485.25	4,638,808.16	(4,130,591.63)	343,313.78	(1,115,443.13)	22,154,787.03
65															
66															
67	Total Deferral	$	(1,581,546.67)	4,902,871.98	(202,975.57)	12,115,060.27	10,108,117.55	1,254,950.60	3,077,981.96	7,198,733.70	8,418,667.35	(4,058,368.54)	(3,451,930.13)	(3,463,503.16)	34,318,059.34
68															
69															
70	Principal Balances														
71															
72	Beginning Balance	$	-	(1,581,546.67)	3,321,325.31	3,118,349.74	15,233,410.01	25,341,527.56	26,596,478.16	29,674,460.12	36,873,193.82	45,291,861.17	41,233,492.63	37,781,562.50	
73															
74	Amount Deferred	$	(1,581,546.67)	4,902,871.98	(202,975.57)	12,115,060.27	10,108,117.55	1,254,950.60	3,077,981.96	7,198,733.70	8,418,667.35	(4,058,368.54)	(3,451,930.13)	(3,463,503.16)	34,318,059.34
75															
76	Ending Balance	$	(1,581,546.67)	3,321,325.31	3,118,349.74	15,233,410.01	25,341,527.56	26,596,478.16	29,674,460.12	36,873,193.82	45,291,861.17	41,233,492.63	37,781,562.50	34,318,059.34	
77															
78	Interest Balances														
79															
80	Accrual thru Prior Month	$	-	-	6,208.44	21,015.08	34,996.75	49,688.52	62,392.51	78,739.41	99,284.61	120,708.69	145,440.03	170,073.98	
81															
82	Monthly Interest Rate **		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
83															
84	Monthly Interest Inc/(Exp)	$	-	6,208.44	14,806.64	13,981.67	14,691.77	12,703.99	16,346.90	20,545.20	21,424.08	24,731.34	24,633.95	27,848.07	197,922.05
85	Prior Month's Interest Adjustments	$	-												-
86	Total Current Month Interest	$	-	6,208.44	14,806.64	13,981.67	14,691.77	12,703.99	16,346.90	20,545.20	21,424.08	24,731.34	24,633.95	27,848.07	197,922.05
87															
88	Interest Accrued to date	$	-	6,208.44	21,015.08	34,996.75	49,688.52	62,392.51	78,739.41	99,284.61	120,708.69	145,440.03	170,073.98	197,922.05	
89															
90	Balance in All Accounts	$	(1,581,546.67)	3,327,533.75	3,139,364.82	15,268,406.76	25,391,216.08	26,658,870.67	29,753,199.53	36,972,478.43	45,412,569.86	41,378,932.66	37,951,636.48	34,515,981.39	34,515,981.39

Exhibit No. 1
Case No. IPC-E-15-14
S. Wright, IPC
Page 1 of 2

Idaho Power Company
PCA Deferral Expense Report
Filed April 15, 2015

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
91															
92															
93															
94	True-Up of True-Up	$	19,140,917.08	74,117,446.50	43,010,771.76	38,605,440.87	33,211,041.73	27,876,944.89	23,509,394.62	19,768,644.53	16,330,931.09	12,535,848.09	8,585,671.18	4,860,554.42	19,140,917.08
95	Adjustments:														-
96	Revenue Sharing Order No. 33049			(7,624,232.79)											(7,624,232.79)
97	DSM Rider Forecasted Surplus Funds Order No. 33049			(20,000,000.00)											(20,000,000.00)
98	2013-14 PCA trnsfr per IPUC Ord No.	$	58,088,875.66												58,088,875.66
99															
100	True-Up of True-Up Balance	$	77,229,792.74	46,493,213.71	43,010,771.76	38,605,440.87	33,211,041.73	27,876,944.89	23,509,394.62	19,768,644.53	16,330,931.09	12,535,848.09	8,585,671.18	4,860,554.42	49,605,559.95
101															
102	Monthly Interest Rate		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
103															
104	Monthly Interest	$	64,358.16	38,744.34	35,842.31	32,171.20	27,675.87	23,230.79	19,591.16	16,473.87	13,609.11	10,446.54	7,154.73	4,050.46	293,348.54
105															
106	True-Up of True-Up Including Interest	$	77,294,150.90	46,531,958.05	43,046,614.07	38,637,612.07	33,238,717.60	27,900,175.68	23,528,985.78	19,785,118.40	16,344,540.20	12,546,294.63	8,592,825.91	4,864,604.88	49,898,908.49
107															
108	Monthly Collection Applied To Balance	$	3,176,704.40	3,521,186.29	4,441,173.20	5,426,570.34	5,361,772.71	4,390,781.06	3,760,341.25	3,454,187.31	3,808,692.11	3,960,623.45	3,732,271.49	3,380,089.98	48,414,393.59
109															
110	Ending True-Up of the True-Up Balance	$	74,117,446.50	43,010,771.76	38,605,440.87	33,211,041.73	27,876,944.89	23,509,394.62	19,768,644.53	16,330,931.09	12,535,848.09	8,585,671.18	4,860,554.42	1,484,514.90	1,484,514.90
111															
112	Negative amounts indicate benefit to the customer.														
113															
114															
115															
116															
117															

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-15-14

IDAHO POWER COMPANY

WRIGHT, DI
TESTIMONY

EXHIBIT NO. 2

Idaho Power Company
Calculation of Revenue Impact
Class Allocated Revenue and Rider Sharing Benefits
State of Idaho
Filed April 15, 2015

Line No	Tariff Description	Rate Sch. No.	(A) Allocated Revenue Sharing Benefit	(B) Allocated DSM Rider (Ongoing) Transfer	(C) Revenue Sharing Dollars per kWh Rate	(D) Allocated DSM Rider (Ongoing) Transfer Dollars per kWh Rate	(E) PCA per kWh Rate	(F) Revenue Sharing + Ongoing DSM Rider Transfer + PCA Rate
	Uniform Tariff Rates:							
1	Residential Service	1	($3,546,973)	($1,421,063)	($0.000713)	($0.000286)	$0.005405	$0.004406
2	Master Metered Mobile Home Park	3	($3,432)	($1,443)	($0.000679)	($0.000286)	$0.005405	$0.004440
3	Residential Service Energy Watch	4	$0	$0	$0.000000	($0.000286)	$0.005405	$0.005119
4	Residential Service Time-of-Day	5	($17,591)	($7,349)	($0.000684)	($0.000286)	$0.005405	$0.004436
5	Small General Service	7	($124,864)	($39,765)	($0.000897)	($0.000286)	$0.005405	$0.004222
6	Large General Service - Secondary	9S	($1,751,310)	($937,227)	($0.000534)	($0.000286)	$0.005405	$0.004585
7	Large General Service - Primary	9P	($220,153)	($135,725)	($0.000463)	($0.000286)	$0.005405	$0.004656
8	Large General Service - Transmission	9T	($1,783)	($1,053)	($0.000484)	($0.000286)	$0.005405	$0.004636
9	Dusk to Dawn Lighting	15	($9,928)	($1,817)	($0.001560)	($0.000286)	$0.005405	$0.003559
10	Large Power Service - Secondary	19S	($2,906)	($1,793)	($0.000463)	($0.000286)	$0.005405	$0.004656
11	Large Power Service - Primary	19P	($899,740)	($626,679)	($0.000410)	($0.000286)	$0.005405	$0.004709
12	Large Power Service - Transmission	19T	($12,714)	($9,222)	($0.000394)	($0.000286)	$0.005405	$0.004725
13	Agricultural Irrigation Service	24	($1,049,197)	($518,592)	($0.000578)	($0.000286)	$0.005405	$0.004541
14	Unmetered General Service	40	($7,441)	($3,324)	($0.000639)	($0.000286)	$0.005405	$0.004480
15	Street Lighting	41	($28,062)	($7,838)	($0.001022)	($0.000286)	$0.005405	$0.004097
16	Traffic Control Lighting	42	($1,282)	($810)	($0.000452)	($0.000286)	$0.005405	$0.004667
17	Total Uniform Tariffs		($7,677,377)	($3,713,702)				
18	Special Contracts							
19	Micron	26	($175,551)	($135,398)	NA	($0.000286)	$0.005405	$0.005119
20	J R Simplot	29	($67,873)	($56,787)	NA	($0.000286)	$0.005405	$0.005119
21	DOE	30	($78,343)	($64,148)	NA	($0.000286)	$0.005405	$0.005119
22	Total Special Contracts		($321,768)	($256,334)				
23	Total Idaho Retail Sales		($7,999,145)	($3,970,036)				

Note:
(1) June 1, 2015 - May 31, 2016 Forecasted Test Year