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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, 2014, THROUGH MAY 31, 2015, AND TO UPDATE BASE RATES IN COMPLIANCE WITH ORDER NO. 33000.	CASE NO. IPC-E-14-05

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, and the NERA "Marginal Costing for Electric Utilities", in Los Angeles, California.

Q. Please describe your work experience.

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 ("PCA") 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 purpose of your testimony?

A. The purpose of my testimony is to present the quantification of the 2014-2015 PCA rates and to quantify the rate listed on Schedule 89, Unit Avoided Energy Cost for Cogeneration and Small Power Production ("Schedule 89").

Q. Please provide a summary of the sections presented in your testimony.

A. My testimony is divided into several sections. The first section of my testimony provides an overview of the PCA components. The second section presents the quantification of the PCA forecast rate using the PCA components approved in Order No. 33000 in Case No. IPC-E-13-20. The third section details the quantification of the True-Up and the True-Up of the True-Up. The fourth section addresses revenue sharing benefits and the proposal to transfer surplus Idaho Energy Efficiency Rider ("DSM Rider") funds, which are described in more detail in Mr. Timothy E. Tatum's testimony. The final section of my testimony describes the update to the Company's Schedule 89.

I. OVERVIEW OF PCA COMPONENTS

Q. Please describe the components of the PCA base.

A. The PCA base level expenses are reflective of 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 expense component for FERC Account 555 includes both power purchases resulting from the Public Utility Regulatory Policies Act of 1978 ("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. QUANTIFICATION OF PCA FORECAST

Q. Were there any changes to this year's PCA base components compared to last year's PCA base components?

A. Yes. On March 21, 2014, Order No. 33000 in Case No. IPC-E-13-20 approved the new base level components used for quantifying this year's PCA rates.

Q. Please quantify the PCA component amounts described previously that are included in the PCA base from which deviations are to be tracked based on customers receiving a 95 percent share.

A. Order No. 33000 approved the Company's base level PCA component amounts from which deviations are to be tracked at 95 percent for customer responsibility as follows:

Account 501, coal	$108,503,180
Account 536, water for power	$2,380,597
Account 547, gas	$33,367,563
Account 555, non-PURPA	$62,606,593
Account 565, transmission	$5,455,955
Account 447, surplus sales	($51,735,153)
Net of 95 percent accounts	$160,578,735

Q. Please quantify the PCA component amounts included in the PCA base from which deviations are to be tracked with a 100 percent customer responsibility.

A. Order No. 33000 approved the PCA base component amounts from which deviations are to be tracked with 100 percent customer responsibility as follows:

Account 555, PURPA	$133,853,869

Q. Please quantify the PCA component amounts included in the PCA base from which deviations are tracked differently than described above.

A. The base level recovery of demand response incentives in the amount of $11,252,265 was approved per Order No. 33000. The $11,252,265 represents the Idaho jurisdictional share of the incentive costs. Because the demand response incentive payments are jurisdictionalized prior to inclusion in the PCA, this cost category is calculated separately from the net 95 percent accounts. Under this separate treatment, an Idaho jurisdictional sales denominator is used rather than the normalized system firm sales denominator used for 95 percent accounts in the PCA rate development process.

Q. Please detail the amounts included in the PCA forecast for which deviations from base are to be tracked based upon a 95 percent customer sharing percentage.

A. Based upon the Company's March 27, 2014, Operating Plan ("Operating Plan"), the forecast of amounts for which deviations from base are to be tracked at 95 percent for customer responsibility is as follows:

Account 501, coal	$169,424,879
Account 536, water for power	$1,751,000
Account 547, gas	$73,941,673
Account 555, non-PURPA	$61,996,853

Account 565, transmission	$6,645,775
Account 447, surplus sales	($126,166,913)
Net of 95 percent accounts	$187,593,267

Q. What is the difference between the net of the 95 percent accounts of the forecast amount of $187,593,267 and the $160,578,735 PCA base amount approved in Order No. 33000?

A. The PCA forecast amount of $187,593,267 is higher than the base amount of $160,578,735, a difference of $27,014,532.

Q. What is the Operating Plan quantification of PURPA expenses anticipated from April 2014 through March 2015?

A. The Operating Plan anticipates $134,142,386 of PURPA expenses during the April 2014 through March 2015 time period.

Q. How does this amount compare to the base level of PURPA expenses approved in Order No. 33000?

A. The Operating Plan quantification of PURPA expense is $288,517 greater than the base level amount of $133,853,869 approved in Order No. 33000.

Q. What is the Operating Plan quantification of the demand response incentive payments anticipated from April 2014 through March 2015?

A. The Operating Plan anticipates $8,290,603 of Idaho jurisdictional demand response incentive payments during the April 2014 through March 2015 time period.

Q. How does this amount compare to the base level of Idaho jurisdictional demand response incentive payments quantified in Order No. 33000?

A. The Operating Plan quantification of demand response incentive payments is $2,961,662 less than the $11,252,265 quantified in the Company's update of power supply expenses approved per Order No. 33000. The lower incentive payments reflect the newly established demand response incentive structure as agreed to by the settlement stipulation approved by the Idaho Public Utilities Commission ("Commission") in Order No. 32923.

Q. What is the rate for the projection portion of the PCA for April 2014 through March 2015?

A. The rate for the projection 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.

The rate for non-PURPA expenses is 0.1807 cents per kilowatt-hour ("kWh"), which is calculated by multiplying $27,014,532 by 95 percent and then dividing it by the normalized system firm sales of 14,200,871 megawatt-hours ("MWh") (($27,014,532 * 0.95) / 14,200,871) = $1.81/MWh = 0.1807 cents/kWh). The rate for PURPA expenses is 0.0020 cents per kWh, which is calculated by dividing $288,517 by the 14,200,871 MWh ($288,517 / 14,200,871 MWh = $0.02/MWh = 0.0020 cents/kWh). The rate for the demand response incentive payment is a negative 0.0218 cents per kWh, which is calculated by dividing a negative $2,961,662 by the Idaho jurisdictional firm sales of 13,558,865 MWh (-$2,961,662 / 13,558,865 MWh = -$0.22/MWh = -0.0218 cents/kWh). The projection portion of the PCA rate is 0.1609 cents per kWh, which is calculated by adding the non-PURPA expense of 0.1807 cents per kWh to the PURPA expense of 0.0020 cents per kWh to the demand response incentive payment of negative 0.0218 cents per kWh (0.1807 + 0.0020 + -0.0218 = 0.1609 cents/kWh).

Q. What is the recoverable deviation of forecast power supply expenses from base level power supply expenses for the 2014-2015 PCA forecast?

A. The recoverable portion of power supply expenses is $22,990,660 million (($27,014,532 x 0.95) + $288,517 + -$2,961,662 = $22,990,660).

III. <u>QUANTIFICATION OF THE TRUE-UP AND TRUE-UP OF THE TRUE-UP</u>

Q. Please describe the True-Up portion of the PCA rate.

A. The True-Up portion of the PCA rate starts with the deferral expense report, attached as Exhibit No. 5. 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 2014, with interest applied, was $58,088,876, as shown on row 90 of Exhibit No. 5. The $58.1 million represents a charge to customers largely resulting from actual power supply expenses being greater than what had been forecast last year.

Q. Please describe the computation of this year's True-Up rate.

A. This year's True-Up component of the PCA is $58,088,876, divided by the Company's projected Idaho jurisdictional sales of 13,558,865 MWh which results in a rate of 0.4284 cents per kWh ($58,088,876 / 13,558,865 = $4.28/MWh = 0.4284 cents/kWh).

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

A. The Company under collected last year's PCA True-Up Balance by $19,140,917 as shown on row 109 of the deferral expense report. The True-Up of the True-Up rate is calculated by dividing $19,140,917 by the projected Idaho jurisdictional sales of 13,558,865 MWh, which results in a rate of 0.1412 cents per kWh ($19,140,917 / 13,558,865 = $1.41/MWh = 0.1412 cents/kWh).

Q. Please explain 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 $58.1 million associated with the True-Up and the $19.1 million associated with the True-Up of the True-Up represents $77.2 million 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. 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. 5 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.

IV. REVENUE SHARING AND DSM RIDER ADJUSTMENT

Q. Please give a brief overview of the revenue sharing and DSM Rider adjustment proposal described in Mr. Tatum's testimony.

A. The revenue sharing and DSM Rider adjustment proposal includes a revenue sharing benefit of $7,602,043 as well as a transfer of DSM Rider funds of $20 million.

Q. How has the Company incorporated this refund into the PCA rate?

A. As detailed in Mr. Tatum's testimony, the Company plans to apportion the revenue sharing benefits and the transfer of $16 million in DSM Rider funds based on each class's proportion of base revenues. The transfer of $4 million in DSM Rider funds that is necessary to ensure a revenue neutral implementation of the 2013 base level NPSE 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. 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 transfer of DSM Rider funds will be provided in the form of a volumetric rate for all classes of customers. Exhibit No. 6, page 1, columns A, B, and C show the annual revenue sharing benefits and the transfer of DSM Rider funds for all classes of customers. Columns D, E, and F show the cents per kWh rate for the classes that will receive revenue sharing benefits and the transfer of DSM Rider funds 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 2014-2015 PCA year is detailed in Exhibit No. 6, page 1, column H. The uniform PCA rate is comprised of (1) the 0.1609 cents per kWh adjustment for the 2014-2015 projected power cost of serving firm loads, under the current PCA methodology and 95 percent sharing, (2) the 0.4284 cents per kWh for the 2013-2014 True-Up portion of the PCA, and (3) the 0.1412 cents per kWh for the True-Up of the True-Up. The sum of these three components results in a 0.7305 cents per kWh charge for all rate classes.

In addition to the uniform PCA rate, each rate class is assigned a portion of the $7.6 million of revenue sharing and a portion of the $20 million related to the transfer of DSM Rider funds. 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 transfer of DSM Rider funds are listed by rate schedule in Exhibit No. 6, page 1, column I.

Q. Have you calculated the expected PCA revenue using the PCA rates described above?

A. Yes. The Company would expect to collect $99.0 million through the uniform PCA rate using the approved base power supply expenses approved in Order No. 33000. This is $67.9 million less than the $166.9 million associated with the current PCA rate. When the uniform PCA rate is combined with the additional $7.6 million in revenue sharing and $20 million for the transfer of DSM Rider funds, the Company would expect to collect $71.4 million through the final combined PCA rates.

Q. What is the revenue impact of the requested PCA rate combined with the revenue sharing rates and the transfer of DSM Rider funds 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 2014 through May 2015 test year results in a PCA increase of $11.1 million.

V. SCHEDULE 89 UPDATE

Q. Please provide a brief overview of Schedule 89.

A. In 1980, Schedule 89 was created pursuant to Order Nos. 15746 and 16025 to provide PURPA contracts with an updated avoided energy cost rate any time the Company updated its variable power supply expenses.

Q. Why is the Company updating Schedule 89 in this proceeding?

A. The Company is updating Schedule 89 pursuant to Order No. 32758 issued in Case No. IPC-E-12-28. Order No. 32758 directs the Company to update Schedule 89 whenever NPSE amounts are updated, whereas typically this update only occurred after a general rate case has been approved. On March 21, 2014, Order No. 33000 approved updated NPSE amounts for the Company.

Q. How is Schedule 89 calculated?

A. Schedule 89 is calculated by combining Valmy's variable power supply expense approved per Order No. 33000 and the variable operations and maintenance expenses associated with the plant.

Q. Has the Company provided the proposed Schedule 89 tariff for approval?

A. Yes. The Company has included an updated Schedule 89 in Attachment 1 to the application.

Q. Should the Commission approve the Company's computation of the PCA rates using the PCA mitigation calculations and the update to Schedule 89?

A. Yes. The Commission should approve the Company's computation of the PCA rates using the PCA mitigation calculations as well as the update to Schedule 89. The calculation of the PCA rates and the update to Schedule 89 follows the methodology that was approved in Order Nos. 30715, 30978, 32424, 32578, and 33000.

Q. Does this conclude your testimony?

A. Yes.

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, 2014.

____
Scott Wright

SUBSCRIBED AND SWORN to before me this 15th day of April, 2014.

KIMBERLY K. TOWELL
NOTARY PUBLIC
STATE OF IDAHO

Kimberly K. Towell
Notary Public for Idaho
Residing at: Star, Idaho
My commission expires: 12-20-2014

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-14-05

IDAHO POWER COMPANY

WRIGHT, DI
TESTIMONY

EXHIBIT NO. 5

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Power Cost Adjustment**														
2	**April 2013 thru March 2014**		April	May	June	July	August	September	October	November	December	January	February	March	Totals
3															
4	**PCA Forecasted Revenues**														
5	Actual Idaho Jurisdictional Sales*	Mwh	922,125	931,654	350,250	1,506,796	1,586,090	1,370,093	1,002,511	938,372	1,093,779	1,180,245	1,111,808	950,799	12,944,522
6	PCA Component Rate	$	5.099	5.099	8.258	8.258	8.258	8.258	8.258	8.258	8.258	8.258	8.258	8.258	
7	Forecasted Revenues	$	4,701,915.24	4,750,503.75	2,892,364.50	12,443,121.37	13,097,931.22	11,314,227.99	8,278,735.84	7,749,075.98	9,032,426.98	9,746,463.21	9,181,310.46	7,851,698.14	101,039,774.68
8															
9	**Load Change Adjustment**														
10	Actual Firm Load - Adjusted	Mwh	1,076,204	1,328,511	1,552,985	1,793,750	1,654,552	1,192,855	1,068,601	1,102,929	1,368,173	1,282,108	1,083,454	1,063,476	15,567,598
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	29,140	56,806	159,311	49,659	68,321	(86,299)	(29,855)	(29,043)	9,778	(64,204)	(55,754)	(71,399)	36,461
13	Expense Adjustment ($17.64)		(514,029.60)	(1,002,057.84)	(2,810,246.04)	(875,984.76)	(1,205,182.44)	1,522,314.36	526,642.20	512,318.52	(172,483.92)	1,132,558.56	983,500.56	1,259,478.36	(643,172.04)
14															
15	**Actual Non-QF PCA**														
16	Expense Adjustment	$	(514,029.60)	(1,002,057.84)	(2,810,246.04)	(875,984.76)	(1,205,182.44)	1,522,314.36	526,642.20	512,318.52	(172,483.92)	1,132,558.56	983,500.56	1,259,478.36	(643,172.04)
17	Fuel Expense-Coal	$	8,027,505.39	10,281,417.67	13,890,511.77	14,894,959.23	16,158,574.32	12,711,963.15	12,721,006.93	15,084,509.97	16,190,308.58	17,881,322.76	14,983,221.23	8,170,369.11	160,995,670.11
18	Fuel Expense-Gas	$	1,486,609.66	2,698,999.53	5,400,086.67	7,146,219.67	7,870,881.69	5,974,809.92	1,454,620.35	4,857,341.46	8,159,706.24	6,989,544.19	5,657,873.19	1,532,113.20	59,228,805.77
19	Non-Firm Purchases	$	3,743,953.41	4,453,122.82	5,532,094.89	14,646,693.58	10,455,494.22	5,294,844.08	5,661,426.75	6,923,617.75	9,030,512.61	4,052,608.70	4,854,878.57	3,874,439.43	78,523,686.81
20	Third Party Transmission	$	257,798.71	357,848.12	763,791.98	897,308.52	796,449.60	512,841.64	492,774.73	346,525.93	343,672.66	338,567.63	325,776.14	327,361.86	5,760,717.52
21	Surplus Sales	$	(1,442,293.21)	(1,223,681.40)	(1,450,263.51)	(2,397,723.56)	(2,031,595.03)	(6,426,201.12)	(6,225,006.78)	(9,125,878.48)	(7,451,786.86)	(8,385,471.11)	(9,811,088.00)	(10,813,741.54)	(66,784,730.60)
22	Hoku 1st Block Energy	$	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Water for Power (Leases)	$	-	-	101,661.30	571,450.00	-	-	-	-	-	-	33,300.00	-	706,411.30
24	Total Non-QF	$	11,559,544.36	15,565,648.90	21,427,637.06	34,882,922.68	32,044,622.36	19,590,572.03	14,631,464.18	18,598,435.15	26,099,929.31	22,009,130.73	17,027,461.69	4,350,020.42	237,787,388.87
25															
26	**BASE**														
27	Fuel Expense-Coal	$	11,311,629.00	11,169,485.00	14,209,042.00	17,844,222.00	18,884,185.00	16,870,940.00	12,089,048.00	11,213,235.00	13,247,390.00	14,688,304.00	13,477,403.00	12,187,860.00	167,192,743.00
28	Fuel Expense-Gas	$	3,513,672.00	3,469,518.00	4,413,680.00	5,542,857.00	5,865,895.00	5,240,531.00	3,755,157.00	3,483,108.00	4,114,967.00	4,562,550.00	4,186,415.00	3,785,851.00	51,934,201.00
29	Non-Firm Purchases	$	3,079,041.00	3,040,349.00	3,867,721.00	4,857,222.00	5,140,301.00	4,592,293.00	3,290,655.00	3,052,258.00	3,605,958.00	3,998,176.00	3,668,568.00	3,317,552.00	45,510,094.00
30	Third Party Transmission	$	558,976.00	551,952.00	702,154.00	881,790.00	933,181.00	833,695.00	597,393.00	554,113.00	654,633.00	725,838.00	666,000.00	602,275.00	8,262,000.00
31	Hoku 1st Block Energy	$	(1,618,436.00)	(1,598,098.00)	(2,032,990.00)	(2,553,101.00)	(2,701,896.00)	(2,413,847.00)	(1,729,667.00)	(1,604,358.00)	(1,895,399.00)	(2,101,561.00)	(1,928,309.00)	(1,743,805.00)	(23,921,467.00)
32	Surplus Sales	$	(8,451,355.00)	(8,345,154.00)	(10,616,124.00)	(13,332,107.00)	(14,109,103.00)	(12,604,931.00)	(9,032,194.00)	(8,377,841.00)	(9,897,636.00)	(10,974,199.00)	(10,069,488.00)	(9,106,021.00)	(124,916,153.00)
33	Water for Power (Leases)	$	123,719.00	122,164.00	155,409.00	195,168.00	206,542.00	184,523.00	132,222.00	122,643.00	144,891.00	160,651.00	147,407.00	133,301.00	1,828,640.00
34	Net 95% Items	$	8,517,246.00	8,410,216.00	10,698,892.00	13,436,051.00	14,219,105.00	12,703,204.00	9,102,614.00	8,443,158.00	9,974,804.00	11,059,759.00	10,147,996.00	9,177,013.00	125,890,058.00
35															
36	Change From Base	$	3,042,298.36	7,155,432.90	10,728,745.06	21,446,871.68	17,825,517.36	6,887,368.03	5,528,850.18	10,155,277.15	16,125,125.31	10,949,371.73	6,879,465.69	(4,826,992.58)	111,897,330.87
37	Emission Allowance Sales Credit	$	-	-	-	-	-	-	(24,000.00)	-	-	-	-	-	(24,000.00)
38	Renewable Energy Credit Sales	$	(465,967.44)	1,105.88	(14,003.50)	(2,427.63)	(8,524.37)	329.95	(8,369.71)	(57,748.49)	329.01	(397,330.59)	(657,345.02)	(264,939.75)	(1,874,891.66)
39	Subtotal	$	2,576,330.92	7,156,538.78	10,714,741.56	21,444,444.05	17,816,992.99	6,887,697.98	5,496,480.47	10,097,528.66	16,125,454.32	10,552,041.14	6,222,120.67	(5,091,932.33)	109,998,439.21
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**	$	2,325,138.66	6,458,776.25	9,670,054.26	19,353,610.76	16,079,836.17	6,216,147.43	4,960,573.62	9,113,019.62	14,553,222.52	9,523,217.13	5,615,463.90	(4,595,468.93)	99,273,591.39
45															
46	**Demand Response Incentive Payments**														
47	Actual	$	42.00	-	878,814.08	2,198,386.34	834,126.34	283,951.63	7,764.16	-	9.77	(5,880.21)	-	-	4,197,214.11
48	Base	$	761,286.00	751,719.00	956,285.00	1,200,937.00	1,270,927.00	1,135,434.00	813,607.00	754,664.00	891,565.00	988,540.00	907,045.00	820,257.00	11,252,266.00
49	Change From Base	$	(761,244.00)	(751,719.00)	(77,470.92)	997,449.34	(436,800.66)	(851,482.37)	(805,842.84)	(754,664.00)	(891,555.23)	(994,420.21)	(907,045.00)	(820,257.00)	(7,055,051.89)
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**	$	(761,244.00)	(751,719.00)	(77,470.92)	997,449.34	(436,800.66)	(851,482.37)	(805,842.84)	(754,664.00)	(891,555.23)	(994,420.21)	(907,045.00)	(820,257.00)	(7,055,051.89)
55															
56															
57	Actual QF (Includes Net Metering, Raft River 100% & Liquidated Damages)	$	10,572,548.29	10,908,935.50	11,681,713.06	12,831,995.33	12,662,857.42	12,673,489.55	10,763,930.10	10,063,744.69	11,107,040.42	10,292,763.69	10,529,045.11	8,915,029.62	133,003,092.78
58	Base QF	$	4,252,292.00	4,198,857.00	5,341,493.00	6,708,038.00	7,098,983.00	6,342,160.00	4,544,541.00	4,215,303.00	4,979,987.00	5,521,659.00	5,066,454.00	4,581,687.00	62,851,454.00
59	Change From Base	$	6,320,256.29	6,710,078.50	6,340,220.06	6,123,957.33	5,563,874.42	6,331,329.55	6,219,389.10	5,848,441.69	6,127,053.42	4,771,104.69	5,462,591.11	4,333,342.62	70,151,638.78
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**	$	6,004,243.48	6,374,574.58	6,023,209.06	5,817,759.46	5,285,680.70	6,014,763.07	5,908,419.65	5,556,019.61	5,820,700.75	4,532,549.46	5,189,461.55	4,116,675.49	66,644,056.86
65															
66															
67	**Total Deferral**	$	2,866,222.90	7,331,128.08	12,723,427.90	13,725,698.19	7,830,784.99	65,200.14	1,784,414.59	6,165,299.25	10,449,941.06	3,314,883.17	716,569.99	(9,150,748.58)	57,822,821.68
68															
69															
70	Principal Balances														
71															
72	Beginning Balance	$	-	2,866,222.90	10,197,350.98	22,920,778.88	36,646,477.07	44,477,262.06	44,542,462.20	46,326,876.79	52,492,176.04	62,942,117.10	66,257,000.27	66,973,570.26	
73															
74	Amount Deferred	$	2,866,222.90	7,331,128.08	12,723,427.90	13,725,698.19	7,830,784.99	65,200.14	1,784,414.59	6,165,299.25	10,449,941.06	3,314,883.17	716,569.99	(9,150,748.58)	57,822,821.68
75															
76	Ending Balance	$	2,866,222.90	10,197,350.98	22,920,778.88	36,646,477.07	44,477,262.06	44,542,462.20	46,326,876.79	52,492,176.04	62,942,117.10	66,257,000.27	66,973,570.26	57,822,821.68	
77															
78	Interest Balances														
79															
80	Accrual thru Prior Month	$	-	-	9,914.91	30,451.57	58,919.41	82,772.82	97,464.34	111,478.19	129,650.23	151,696.99	181,959.31	219,184.96	
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)	$	-	9,914.91	20,536.66	28,467.84	23,853.41	14,691.52	14,013.85	18,172.04	22,046.76	30,262.32	37,225.65	46,869.02	266,053.98
85	Prior Month's Interest Adjustments	$	-	-	-	-	-	-	-	-	-	-	-	-	
86	Total Current Month Interest	$	-	9,914.91	20,536.66	28,467.84	23,853.41	14,691.52	14,013.85	18,172.04	22,046.76	30,262.32	37,225.65	46,869.02	266,053.98
87															
88	Interest Accrued to date	$	-	9,914.91	30,451.57	58,919.41	82,772.82	97,464.34	111,478.19	129,650.23	151,696.99	181,959.31	219,184.96	266,053.98	
89															
90	**Balance in All Accounts**	$	2,866,222.90	10,207,265.89	22,951,230.45	36,705,396.48	44,560,034.88	44,639,926.54	46,438,354.98	52,621,826.27	63,093,814.09	66,438,959.58	67,192,755.22	58,088,875.66	58,088,875.66
91															
92	*April & May reflect Normalized Sales														

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
93															
94	True-Up of True-Up	$	(7,719,348.99)	57,957,853.33	54,667,091.26	56,458,200.09	51,265,223.32	45,753,028.26	40,984,942.69	37,486,864.60	34,216,135.09	30,418,392.85	26,322,799.47	22,457,364.78	(7,719,348.99)
95	Adjustments:														-
96	Revenue Sharing Order No. 32821 (1)			(7,166,125.59)	(5,969.29)										(7,172,094.88)
97	2012-13 PCA trnsfr per IPUC Ord No. 32821	$	62,204,982.23	-	-	-	-	-	-	-	-	-	-	-	62,204,982.23
98															
99	True-Up of True-Up Balance	$	54,485,633.24	50,791,727.74	54,661,121.97	56,458,200.09	51,265,223.32	45,753,028.26	40,984,942.69	37,486,864.60	34,216,135.09	30,418,392.85	26,322,799.47	22,457,364.78	47,313,538.36
100															
101	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%	
102															
103	Monthly Interest	$	45,404.69	42,326.44	45,550.93	47,048.50	42,721.02	38,127.52	34,154.12	31,239.05	28,513.45	25,348.66	21,935.67	18,714.47	421,084.52
104															
105	True-Up of True-Up Including Interest	$	54,531,037.93	50,834,054.18	54,706,672.90	56,505,248.59	51,307,944.34	45,791,155.78	41,019,096.81	37,518,103.65	34,244,648.54	30,443,741.51	26,344,735.14	22,476,079.25	47,734,622.88
106															
107	Monthly Collection Applied To Balance	$	(3,426,815.40)	(3,833,037.08)	(1,751,527.19)	5,240,025.27	5,554,916.08	4,806,213.09	3,532,232.21	3,301,968.56	3,826,255.69	4,120,942.04	3,887,370.36	3,335,162.17	28,593,705.80
108															
109	Ending True-Up of the True-Up Balance	$	57,957,853.33	54,667,091.26	56,458,200.09	51,265,223.32	45,753,028.26	40,984,942.69	37,486,864.60	34,216,135.09	30,418,392.85	26,322,799.47	22,457,364.78	19,140,917.08	19,140,917.08
110															
111	Negative amounts indicate benefit to the customer.														
112															

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-14-05

IDAHO POWER COMPANY

WRIGHT, DI
TESTIMONY

EXHIBIT NO. 6

Idaho Power Company
Calculation of Revenue Impact
Summary of PCA Rate
Idaho Jurisdiction
Filed April 15, 2014

Line No	Tariff Description	Rate Sch. No.	(A) Allocated Revenue Sharing Benefit	(B) Allocated DSM Rider Transfer (One-Time)	(C) DSM Rider Transfer (Ongoing)	(D) Revenue Sharing per kWh Rate	(E) DSM Rider Transfer (One-Time) per kWh Rate	(F) DSM Rider Transfer (Ongoing) per kWh Rate	(G) Total DSM Rider Transfer per kWh Rate	(H) PCA per kWh Rate	(I) PCA + Revenue Sharing + DSM Rider Transfer per kWh Rate
	Uniform Tariff Rates:										
1	Residential Service	1	($3,408,014)	($7,186,271)	($1,436,250)	(0.000695)	(0.001465)	(0.000293)	(0.001758)	0.007305	0.004852
2	Master Metered Mobile Home Park	3	($3,286)	($6,929)	($1,459)	(0.000659)	(0.001390)	(0.000293)	(0.001683)	0.007305	0.004963
3	Residential Service Time-of-Day	5	($17,825)	($37,586)	($7,867)	(0.000663)	(0.001399)	(0.000293)	(0.001692)	0.007305	0.004950
4	Small General Service	7	($124,497)	($262,519)	($41,941)	(0.000869)	(0.001833)	(0.000293)	(0.002126)	0.007305	0.004310
5	Large General Service - Secondary	9S	($1,639,083)	($3,456,233)	($926,478)	(0.000518)	(0.001092)	(0.000293)	(0.001385)	0.007305	0.005402
6	Large General Service - Primary	9P	($208,334)	($439,301)	($135,326)	(0.000451)	(0.000951)	(0.000293)	(0.001243)	0.007305	0.005611
7	Large General Service - Transmissior	9T	($1,130)	($2,382)	($710)	(0.000466)	(0.000982)	(0.000293)	(0.001275)	0.007305	0.005565
8	Dusk to Dawn Lighting	15	($9,708)	($20,472)	($1,874)	(0.001517)	(0.003199)	(0.000293)	(0.003492)	0.007305	0.002296
9	Large Power Service - Secondary	19S	($2,842)	($5,994)	($1,859)	(0.000448)	(0.000944)	(0.000293)	(0.001237)	0.007305	0.005620
10	Large Power Service - Primary	19P	($846,483)	($1,784,927)	($620,699)	(0.000399)	(0.000842)	(0.000293)	(0.001135)	0.007305	0.005771
11	Large Power Service - Transmission	19T	($12,968)	($27,345)	($9,869)	(0.000385)	(0.000811)	(0.000293)	(0.001104)	0.007305	0.005816
12	Agricultural Irrigation Service	24	($986,020)	($2,079,160)	($513,104)	(0.000563)	(0.001186)	(0.000293)	(0.001479)	0.007305	0.005263
13	Unmetered General Service	40	($7,545)	($15,909)	($3,561)	(0.000620)	(0.001308)	(0.000293)	(0.001601)	0.007305	0.005084
14	Street Lighting	41	($26,186)	($55,217)	($7,895)	(0.000971)	(0.002048)	(0.000293)	(0.002341)	0.007305	0.003993
15	Traffic Control Lighting	42	($1,241)	($2,616)	($828)	(0.000439)	(0.000925)	(0.000293)	(0.001218)	0.007305	0.005648
16	Total Uniform Tariffs		($7,295,161)	($15,382,860)	($3,709,719)						
17	Special Contracts										
18	Micron	26	($163,742)	($345,273)	($136,447)	NA[1]	(0.000741)	(0.000293)	(0.001034)	0.007305	0.006271
19	J R Simplot	29	($62,390)	($131,559)	($54,498)	NA[1]	(0.000707)	(0.000293)	(0.001000)	0.007305	0.006305
20	DOE	30	($80,750)	($170,272)	($69,372)	NA[1]	(0.000719)	(0.000293)	(0.001011)	0.007305	0.006294
21	Total Special Contracts		($306,882)	($647,104)	($260,316)						
22	Total Idaho Retail Sales		($7,602,043)	($16,029,964)	($3,970,036)						

Note:
June 1, 2014 - May 31, 2015, Forecast
(1) Revenue Sharing for Special Contracts is applied as a fixed dollar amount each month.

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S. Wright, IPC
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