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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 COST ADJUSTMENT ("PCA") RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2013, THROUGH MAY 31, 2014.	)	CASE NO. IPC-E-13-10

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" course at 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 for ratemaking purposes, preparing the Power Cost Adjustment ("PCA") filings in both 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 quantify the 2013-2014 PCA rates. I have provided this quantification to Mr. Timothy E. Tatum, who will present the Company's recommendation in his testimony.

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 includes a discussion of the quantification of the PCA forecast rate using the PCA base components that were approved in Order No. 31042 in Case No. IPC-E-10-01, Order No. 32426 in Case No. IPC-E-11-08, and Order No. 32585 in Case No. IPC-E-12-14. The third section details the quantification of the True-up and the True-up of the True-up. The fourth section addresses the PCA treatment of the revenue sharing amount that is presented by Ms. Kelley K. Noe in her testimony in this proceeding. The final section of my testimony details the summation of all PCA components, which when combined with the revenue sharing, provides a final PCA rate for each rate class.

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; FERC Account 442, Hoku Materials, Inc. ("Hoku") first block energy; 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. 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 ("95 percent accounts").

A. Order Nos. 31042, 32426, and 32585 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	$167,192,744
Account 536, water for power	$1,828,640
Account 547, gas	$51,934,201
Account 555, non-PURPA	$45,510,093
Account 565, transmission	$8,262,000
Account 442, Hoku first block	($23,921,466)
Account 447, surplus sales	($124,916,153)
Net of 95 percent accounts	$125,890,059

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. 31042 approved the PCA base component amounts from which deviations are to be tracked with 100 percent customer responsibility as follows:

Account 555, PURPA	$62,851,454

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. 32426. 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 28, 2013, 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	$165,951,392
Account 536, water for power	$2,354,374
Account 547, gas	$66,536,064
Account 555, non-PURPA	$40,080,534
Account 565, transmission	$6,692,385
Account 442, Hoku first block	-
Account 447, surplus sales	($98,510,169)
Net of 95 percent accounts	$183,104,580

Q. What is the difference between the net of the 95 percent accounts of the forecast amount of $183,104,580 and the $125,890,059 PCA base amount approved in Order Nos. 31042, 32426, and 32585?

A. The PCA forecast amount of $183,104,580 is higher than the base amount of $125,890,059, a difference of $57,214,521.

Q. What is the Operating Plan quantification of PURPA expenses anticipated from April 2013 through March 2014?

A. The Operating Plan anticipates $131,731,526 of PURPA expenses during the April 2013 through March 2014 time period.

Q. How does this amount compare to the base level of PURPA expenses approved in Order No. 31042?

A. The Operating Plan quantification of PURPA expense is $68,880,072 greater than the base level amount of $62,851,454 (approved in Order No. 31042) in the Company's update of power supply expenses.

Q. What is the Operating Plan quantification of the demand response incentive payments anticipated from April 2013 through March 2014?

A. The Operating Plan anticipates $4,668,960 of Idaho jurisdictional demand response incentive payments during the April 2013 through March 2014 time period.

Q. How does this amount compare to the base level of Idaho jurisdictional demand response incentive payments quantified in Order No. 32426?

A. In Order No. 32776, the Commission recently approved a Settlement Stipulation under which the Company will suspend the operation of two of its three demand response programs in 2013. As a result of this approved program suspension, the Operating Plan quantification of demand response incentive payments is $6,583,305 less than the $11,252,265 quantified in the Company's update of power supply expenses approved per Order No. 32426.

Q. What is the rate for the forecast portion of the PCA for April 2013 through March 2014?

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, (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 0.3858 cents per kilowatt-hour ("kWh"), which is calculated by multiplying $57,214,521 by 95 percent and then dividing it by the normalized system firm sales of 14,088,933 megawatt-hours ("MWh") (($57,214,521 * 0.95) / 14,088,933) = $3.86/MWh = 0.3858 cents/kWh). The rate for PURPA expenses is 0.4889 cents per kWh, which is calculated by dividing $68,880,072 by the 14,088,933 MWh ($68,880,072 / 14,088,933 MWh = $4.89/MWh = 0.4889 cents/kWh). The rate for the demand response incentive payment is (0.0489) cents per kWh, which is calculated by dividing ($6,583,305) by the Idaho jurisdictional firm sales of 13,459,100 MWh (-$6,583,305 / 13,459,100 MWh = -$0.49/MWh = -0.0489 cents/kWh). The forecast portion of the PCA rate is 0.8258 cents per kWh, which is calculated by adding the non-PURPA expense of 0.3858 cents per kWh to the PURPA expense of 0.4889 cents per kWh to the demand response incentive payment of (0.0489) cents per kWh (0.3858 + 0.4889 + -0.0489 = 0.8258 cents/kWh).

Q. What is the recoverable deviation of forecast power supply expenses from base level power supply expenses for the 2013-2014 PCA forecast from Idaho customers?

A. The recoverable portion of power supply expenses is $116,650,562 ($57,214,521 x 0.95) + $68,880,072 + -$6,583,305 = $116,650,562).

III. QUANTIFICATION OF THE TRUE-UP AND TRUE-UP OF THE TRUE-UP

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. 3. 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 with interest at the end of March 2013 was $62,204,982, as shown on row 90 of Exhibit No. 3. The $62.2 million represents a charge to customers resulting from actual power supply expenses being greater than what had been forecasted 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 $62,204,982, divided by the Company's projected Idaho jurisdictional sales of 13,459,100 MWh which results in a rate of 0.4622 cents per kWh ($62,204,982 / 13,459,100 = $4.62/MWh = 0.4622 cents/kWh).

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

A. The Company collected more than quantified in this year's PCA True-up Balance by ($7,719,349), as shown on row 108 of the deferral expense report. The True-up of the True-up rate is calculated by dividing ($7,719,349) by the projected Idaho jurisdictional sales of 13,459,100 MWh, which results in a rate of (0.0574) cents per kWh (-$7,719,349 / 13,459,100 = -$0.57/MWh = -0.0574 cents/kWh). Unlike the True-up calculated earlier, this year's True-up of the True-up is a benefit to customers.

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 $62.2 million associated with the True-up and the ($7.7) million associated with the True-up of the True-up represents $54.5 million of additional collection from customers. This additional cost in large part reflects that actual net power supply expenses for the 2012-2013 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 emission allowance proceeds?

A. Yes. The RECs and sulfur dioxide emission allowance proceeds are included in the Company's deferral expense report, included as Exhibit No. 3 on lines 37 and 38. In Order No. 32002 issued on June 11, 2010, the Commission accepted for filing the Company's REC Management Plan, which passes the customers' share of REC benefits back to customers through the PCA. Order No. 32434 issued on January 12, 2012, directed the Company to pass sulfur dioxide emission allowance proceeds from 2011 through the PCA to help offset the Company's PCA deferral balance.

IV. PCA TREATMENT OF REVENUE SHARING

Q. Based upon the quantification presented by Ms. Noe filed in this year's PCA filing, what is the amount of revenue sharing benefits that the Company proposes to pass on to customers through this year's PCA?

A. As set forth in Ms. Noe's testimony, the Company proposes to pass along revenue sharing benefits of $7,151,221 to customers through this year's PCA.

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

A. As detailed in the "Rate Design" section of Ms. Noe's testimony, the Company plans to apportion the revenue sharing benefits based on each class's proportion of test year base revenues. All classes of customers will receive revenue sharing benefits in the form of a volumetric rate, with the exception of the Company's special contract customers. The Company's special contract customers will receive revenue sharing benefits in the form of a monthly credit on their bill during the 2013-2014 PCA year. Exhibit No. 4, column A, shows the annual benefits for all customers, while column B shows the cents per kWh rate for the class's that will receive revenue sharing amounts in the form of a volumetric rate.

V. **PCA RATE DETERMINATION**

Q. What is the resulting PCA rate when all of the PCA components described previously are combined?

A. The Company's PCA rate for the 2013-2014 PCA year is detailed in Exhibit No. 4, column C. The uniform PCA rate is comprised of (1) the 0.8258 cents per kWh adjustment for the 2013-2014 projected power cost of serving firm loads, under the current PCA methodology and 95 percent sharing, (2) the 0.4622 cents per kWh for the 2012-2013 True-up portion of the PCA, and (3) the (0.0574) cents per kWh for the True-up of the True-up. The sum of these three components results in a 1.2306 cents per kWh charge for all rate classes.

In addition to the uniform PCA rate, each rate class is assigned a portion of the $7.2 million of revenue sharing. When this amount is combined with the uniform PCA rate, each class will receive a different PCA rate. The final PCA rate, including revenue sharing, is listed by rate schedule in Exhibit No. 4, column D.

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

A. Yes. The Company expects to collect $165.6 million through the uniform PCA rate using the base power supply expenses approved in Order Nos. 31042, 32426, and 32585. This represents $121.2 million of incremental revenue above the $44.4 million that the Company expected to collect through the current uniform PCA rate approved in Order No. 32552. When the uniform PCA rate is combined with the additional $7.2 million in revenue sharing, the Company expects to collect an incremental amount of $158.5 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 demand side management rates when compared to the PCA rate currently in effect?

A. Attachment No. 3 to the Application provides a detailed description of the overall revenue impact of this filing on each customer class. As shown on Attachment No. 3, applying the requested PCA rates to expected customer loads for June 2013 through May 2014 test year results in a PCA increase of $140.4 million.

Q. Do the calculations of this year's PCA rates comply with the approved methodology?

A. Yes. The calculation of the PCA rates follows the methodology that was approved in Order Nos. 30715, 30978, 31042, 32424, 32426, and 32585.

Q. Has the Company prepared a revised Schedule 55 that presents the PCA rates that would result from applying the Company's PCA calculations?

A. Yes. Attachment No. 1 to the Application is a revised Schedule 55, in both clean and legislative formats, specifying the proposed PCA rates and changes for providing electric service to customers in the state of Idaho with $140.4 million to be collected during the 2013-2014 PCA year.

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 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, 2013.

____
Scott Wright

SUBSCRIBED AND SWORN to before me this 15th day of April, 2013.

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


KIMBERLY K. TOWELL
NOTARY
PUBLIC
STATE OF IDAHO

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-13-10

IDAHO POWER COMPANY

WRIGHT, DI TESTIMONY

EXHIBIT NO. 3

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Power Cost Adjustment**														
2	**April 2012 thru March 2013**		April	May	June	July	August	September	October	November	December	January	February	March	Totals
3															
4	**PCA Forecasted Revenues**														
5	Normalized Idaho Jurisdictional Sales	Mwh	947,192	953,286	1,100,636	1,338,967	1,416,209	1,282,310	1,028,994	928,924	1,055,150	1,152,449	1,052,464	962,551	13,219,132
6	PCA Component Rate	$	0.445	0.445	5.099	5.099	5.099	5.099	5.099	5.099	5.099	5.099	5.099	5.099	
7	Forecasted Revenues	$	421,500.44	424,212.27	5,612,142.96	6,827,392.73	7,221,249.69	6,538,498.69	5,246,840.41	4,736,583.48	5,380,209.85	5,876,337.45	5,366,513.94	4,908,047.55	58,559,529.46
8															
9	**Load Change Adjustment**														
10	Actual Firm Load - Adjusted	Mwh	1,078,204	1,285,353	1,511,279	1,771,274	1,630,622	1,206,348	1,076,818	1,068,915	1,226,268	1,431,936	1,105,285	1,074,183	15,466,485
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	31,140	13,648	117,605	27,183	44,391	(72,806)	(21,638)	(63,057)	(132,127)	85,624	(33,923)	(60,692)	(64,652)
13	Expense Adjustment Jan - June ($18.16) July - March ($17.64)		(565,502.40)	(247,847.68)	(2,135,706.80)	(479,508.12)	(783,057.24)	1,284,297.84	381,694.32	1,112,325.48	2,330,720.28	(1,510,407.36)	598,401.72	1,070,606.88	1,056,016.92
15	**Actual Non-QF PCA**														
16	Expense Adjustment	$	(565,502.40)	(247,847.68)	(2,135,706.80)	(479,508.12)	(783,057.24)	1,284,297.84	381,694.32	1,112,325.48	2,330,720.28	(1,510,407.36)	598,401.72	1,070,606.88	1,056,016.92
17	Fuel Expense-Coal	$	4,872,319.23	4,527,217.58	7,652,926.10	13,033,134.15	14,670,175.59	14,201,307.39	13,655,610.39	14,720,922.93	16,083,419.56	15,177,603.00	12,917,045.41	12,221,335.85	143,733,017.18
18	Fuel Expense-Gas	$	1,749,314.32	1,649,733.08	700,592.78	5,261,669.21	5,896,209.36	2,775,378.42	1,957,030.57	1,020,298.42	1,841,479.40	5,292,403.40	1,097,332.21	2,352,041.41	31,593,482.58
19	Non-Firm Purchases	$	1,940,890.24	5,499,155.67	4,470,374.03	9,919,525.46	8,152,829.99	1,172,271.02	3,135,991.62	5,262,005.86	6,130,649.75	5,006,440.44	3,045,528.32	2,264,821.80	56,000,484.20
20	Third Party Transmission	$	343,731.65	481,268.34	897,411.67	1,142,031.42	1,122,298.40	318,886.65	443,738.67	444,240.66	183,356.27	296,719.08	281,716.33	289,830.86	6,245,230.00
21	Surplus Sales	$	(5,146,913.01)	(4,550,444.07)	(1,485,294.58)	(153,567.49)	(717,282.96)	(3,585,475.91)	(5,189,928.26)	(4,547,401.47)	(7,700,390.16)	(3,358,762.91)	(6,332,412.17)	(5,983,544.51)	(48,751,417.50)
22	Hoku 1st Block Energy	$	(545,550.00)	(545,550.00)	(106,118.29)	-	-	-	-	-	-	-	-	-	(1,197,218.29)
23	Water for Power (Leases)	$	-	-	-	-	2,285,800.00	9,797.00	-	-	-	-	-	-	2,295,597.00
24	Total Non-QF	$	2,648,290.03	6,813,532.92	9,994,184.91	28,723,284.63	30,626,973.14	16,176,462.41	14,384,137.31	18,012,391.88	18,869,235.10	20,903,995.65	11,607,611.82	12,215,092.29	190,975,192.09
25															
26	**BASE**														
27	Fuel Expense-Coal	$	11,347,172.00	11,204,581.00	14,253,689.00	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	167,308,029.00
28	Fuel Expense-Gas	$	410,164.00	405,010.00	515,225.00	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	41,867,730.00
29	Non-Firm Purchases	$	4,511,966.00	4,455,268.00	5,667,682.00	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	50,157,899.00
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	$	(6,267,815.00)	(6,189,053.00)	(7,873,283.00)	(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)	(117,833,671.00)
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	$	9,065,746.00	8,951,824.00	11,387,886.00	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	127,669,160.00
36	**Change From Base**	$	(6,417,455.97)	(2,138,291.08)	(1,393,701.09)	15,287,233.63	16,407,868.14	3,473,258.41	5,281,523.31	9,569,233.88	8,894,431.10	9,844,236.65	1,459,615.82	3,038,079.29	63,306,032.09
37	Emission Allowance Sales Credit	$	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Renewable Energy Credit Sales	$	(906,557.04)	(233,139.60)	(267,300.77)	(365,021.35)	(837,670.48)	(39,333.74)	242.88	(30,883.69)	496.36	223.86	200.31	299.08	(2,678,444.18)
39	Subtotal	$	(7,324,013.01)	(2,371,430.68)	(1,661,001.86)	14,922,212.28	15,570,197.66	3,433,924.67	5,281,766.19	9,538,350.19	8,894,927.46	9,844,460.51	1,459,816.13	3,038,378.37	60,627,587.91
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**	$	(6,609,921.74)	(2,140,216.19)	(1,499,054.18)	13,467,296.58	14,052,103.39	3,099,117.01	4,766,793.99	8,608,361.05	8,027,672.03	8,884,625.61	1,317,484.06	2,742,136.48	54,716,398.09
46	**Demand Response Incentive Payments**														
47	Actual	$	-	-	1,121,363.90	3,885,011.97	7,348,157.34	1,992,162.34	156,160.10	140.10	(23,548.34)	21.00	-	40.13	14,479,508.54
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**	$	(761,286.00)	(751,719.00)	165,078.90	2,684,074.97	6,077,230.34	856,728.34	(657,446.90)	(754,523.90)	(915,113.34)	(988,519.00)	(907,045.00)	(820,216.87)	3,227,242.54
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**	$	(761,286.00)	(751,719.00)	165,078.90	2,684,074.97	6,077,230.34	856,728.34	(657,446.90)	(754,523.90)	(915,113.34)	(988,519.00)	(907,045.00)	(820,216.87)	3,227,242.54
55															
56															
57	Actual QF (Includes Net Metering & Raft River 100%)	$	8,407,170.59	9,535,747.84	12,481,001.90	13,480,102.21	12,259,095.60	10,777,608.62	7,634,248.73	10,037,768.83	12,504,334.85	9,218,136.41	11,667,999.39	10,786,158.35	128,789,373.32
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**	$	4,154,878.59	5,336,890.84	7,139,508.90	6,772,064.21	5,160,112.60	4,435,448.62	3,089,707.73	5,822,465.83	7,524,347.85	3,696,477.41	6,601,545.39	6,204,471.35	65,937,919.32
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**	$	3,947,134.66	5,070,046.30	6,782,533.46	6,433,461.00	4,902,106.97	4,213,676.19	2,935,222.34	5,531,342.54	7,148,130.46	3,511,653.54	6,271,468.12	5,894,247.78	62,641,023.36
65															
66															
67	**Total Deferral**	$	(3,845,573.52)	1,753,898.84	(163,584.78)	15,757,439.82	17,810,191.01	1,631,022.85	1,797,729.02	8,648,596.21	8,880,479.30	5,531,422.70	1,315,393.24	2,908,119.84	62,025,134.53
68															
69															
70	Principal Balances														
71															
72	Beginning Balance	$	-	(3,845,573.52)	(2,091,674.68)	(2,255,259.46)	13,502,180.36	31,312,371.37	32,943,394.22	34,741,123.24	43,389,719.45	52,270,198.75	57,801,621.45	59,117,014.69	
73															
74	Amount Deferred	$	(3,845,573.52)	1,753,898.84	(163,584.78)	15,757,439.82	17,810,191.01	1,631,022.85	1,797,729.02	8,648,596.21	8,880,479.30	5,531,422.70	1,315,393.24	2,908,119.84	62,025,134.53
75															
76	Ending Balance	$	(3,845,573.52)	(2,091,674.68)	(2,255,259.46)	13,502,180.36	31,312,371.37	32,943,394.22	34,741,123.24	43,389,719.45	52,270,198.75	57,801,621.45	59,117,014.69	62,025,134.53	
77															
78	Interest Balances														
79															
80	Accrual thru Prior Month	$	-	-	5,913.05	19,027.74	28,665.59	36,291.08	43,000.73	50,337.56	61,841.57	79,290.02	103,374.99	136,536.96	
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)	$	-	5,913.05	13,099.18	10,476.68	7,555.37	6,709.65	7,336.83	11,506.12	17,450.25	24,357.93	33,168.36	43,310.74	180,884.16
85	Prior Month's Interest Adjustments	$	-	-	15.51	(838.83)	70.12	-	-	(2.11)	(1.80)	(272.96)	(6.39)	-	(1,036.46)
86	Total Current Month Interest	$	-	5,913.05	13,114.69	9,637.85	7,625.49	6,709.65	7,336.83	11,504.01	17,448.45	24,084.97	33,161.97	43,310.74	179,847.70
87															
88	Interest Accrued to date	$	-	5,913.05	19,027.74	28,665.59	36,291.08	43,000.73	50,337.56	61,841.57	79,290.02	103,374.99	136,536.96	179,847.70	
89															
90	**Balance in All Accounts**	$	(3,845,573.52)	(2,085,761.63)	(2,236,231.72)	13,530,845.95	31,348,662.45	32,986,394.95	34,791,460.80	43,451,561.02	52,349,488.77	57,904,996.44	59,253,551.65	62,204,982.23	62,204,982.23
91															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
92															
93	True-Up of True-Up	$	(5,165,169.03)	(22,517,074.09)	(49,414,325.84)	(47,843,577.50)	(42,441,530.29)	(36,760,395.05)	(31,698,860.14)	(27,806,694.83)	(24,256,823.45)	(20,469,132.25)	(16,033,152.96)	(11,485,507.89)	(5,165,169.03)
94	Adjustments:														-
95	Revenue Sharing Order No. 32558			(27,200,635.53)											(27,200,635.53)
96	2011-12 PCA trnsfr per IPUC Ord No.	$	(17,646,658.22)	-	-	-	-	-	-	-	-	-	-	-	(17,646,658.22)
97															
98	True-Up of True-Up Balance	$	(22,811,827.25)	(49,717,709.62)	(49,414,325.84)	(47,843,577.50)	(42,441,530.29)	(36,760,395.05)	(31,698,860.14)	(27,806,694.83)	(24,256,823.45)	(20,469,132.25)	(16,033,152.96)	(11,485,507.89)	(50,012,462.78)
99															
100	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%	
101															
102	Monthly Interest	$	(19,009.86)	(41,431.42)	(41,178.60)	(39,869.65)	(35,367.94)	(30,633.66)	(26,415.72)	(23,172.25)	(20,214.02)	(17,057.61)	(13,360.96)	(9,571.26)	(317,282.95)
103															
104	True-Up of True-Up Including Interest	$	(22,830,837.11)	(49,759,141.04)	(49,455,504.44)	(47,883,447.15)	(42,476,898.23)	(36,791,028.71)	(31,725,275.86)	(27,829,867.08)	(24,277,037.47)	(20,486,189.86)	(16,046,513.92)	(11,495,079.15)	(50,329,745.73)
105															
106	Monthly Collection Applied To Balance	$	(313,763.02)	(344,815.20)	(1,611,926.94)	(5,441,916.86)	(5,716,503.18)	(5,092,168.57)	(3,918,581.03)	(3,573,043.63)	(3,807,905.22)	(4,453,036.90)	(4,561,006.03)	(3,775,730.16)	(42,610,396.74)
107															
108	Ending True-Up of the True-Up Balance	$	(22,517,074.09)	(49,414,325.84)	(47,843,577.50)	(42,441,530.29)	(36,760,395.05)	(31,698,860.14)	(27,806,694.83)	(24,256,823.45)	(20,469,132.25)	(16,033,152.96)	(11,485,507.89)	(7,719,348.99)	(7,719,348.99)
109															
110	* Negative amounts indicate benefit to the customer.														
111	** Interest rate changed per IPUC Order No. 32403 (Jan 2012)														

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-13-10

IDAHO POWER COMPANY

WRIGHT, DI
TESTIMONY

EXHIBIT NO. 4

Idaho Power Company
Combined Revenue Sharing and PCA

Line No	Tariff Description	Rate Schedule No.	(A) Allocated Revenue Sharing Benefit	(B) Sharing (Cents per kWh)	(C) PCA (Cents per kWh)	(D) PCA + Revenue Sharing (Cents per kWh)
1	Residential Service	1	($3,244,707)	(0.0674)	1.2306	1.1632
2	Master Metered Mobile Home Park	3	($3,126)	(0.0639)	1.2306	1.1667
3	Residential Service Energy Watch	4	$0	0.0000	1.2306	1.2306
4	Residential Service Time-of-Day	5	($16,619)	(0.0646)	1.2306	1.1660
5	Small General Service	7	($123,495)	(0.0861)	1.2306	1.1445
6	Large General Service - Secondary	9S	($1,531,678)	(0.0489)	1.2306	1.1817
7	Large General Service - Primary	9P	($187,329)	(0.0419)	1.2306	1.1887
8	Large General Service - Transmission	9T	($1,018)	(0.0416)	1.2306	1.1890
9	Dusk to Dawn Lighting	15	($9,965)	(0.1550)	1.2306	1.0756
10	Large Power Service - Secondary	19S	($2,689)	(0.0414)	1.2306	1.1892
11	Large Power Service - Primary	19P	($754,041)	(0.0365)	1.2306	1.1941
12	Large Power Service - Transmission	19T	($14,710)	(0.0350)	1.2306	1.1956
13	Agricultural Irrigation Service	24	($920,537)	(0.0539)	1.2306	1.1767
14	Unmetered General Service	40	($7,272)	(0.0598)	1.2306	1.1708
15	Street Lighting	41	($25,672)	(0.0963)	1.2306	1.1343
16	Traffic Control Lighting	42	($1,140)	(0.0406)	1.2306	1.1900
17	Total Uniform Tariffs		($6,843,999)			
18						
19	Special Contracts					
20	Micron	26	($180,702)	NA	1.2306	1.2306
21	J R Simplot	29	($55,194)	NA	1.2306	1.2306
22	DOE	30	($71,326)	NA	1.2306	1.2306
23	Hoku	32	$0	NA	1.2306	1.2306
24	Total Special Contracts		($307,222)			
25						
26	Total Idaho Retail Sales		($7,151,221)			

Note:
June 1, 2013 - May 31, 2014, Forecast