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

TIMOTHY E. TATUM

Q. Please state your name and business address.

A. My name is Timothy E. Tatum and my business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Senior Manager of Cost of Service in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. I have earned a Bachelor of Business Administration degree in Economics and a Master of Business Administration degree from Boise State University. I have also attended electric utility ratemaking courses, including "Practical Skills for The Changing Electrical Industry," a course offered through New Mexico State University's Center for Public Utilities, "Introduction to Rate Design and Cost of Service Concepts and Techniques" presented by Electric Utilities Consultants, Inc., and Edison Electric Institute's "Electric Rates Advanced Course." In 2012, I attended the Utility Executive Course at the University of Idaho.

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power in 1996 as a Customer Service Representative in the Company's Customer Service Center where I handled customer phone calls and other customer-related transactions. In 1999, I began working in the Customer Account Management Center where I was responsible for customer account maintenance in the areas of billing and metering.

In June of 2003, after seven years in customer service, I began working as an Economic Analyst on the Energy Efficiency Team. As an Economic Analyst, I was responsible for ensuring that the demand-side management ("DSM") expenses were accounted for properly, preparing and reporting DSM program costs and activities to management and various external stakeholders, conducting cost-benefit analyses of DSM programs, and providing DSM analysis support for the Company's 2004 Integrated Resource Plan ("IRP").

In August of 2004, I accepted a position as a Regulatory Analyst in Regulatory Affairs. As a Regulatory Analyst, I provided support for the Company's various regulatory activities, including tariff administration, regulatory ratemaking and compliance filings, and the development of various pricing strategies and policies.

In August of 2006, I was promoted to Senior Regulatory Analyst. As a Senior Regulatory Analyst, my responsibilities expanded to include the development of complex financial studies to determine revenue recovery and pricing strategies, including the preparation of the Company's cost-of-service studies.

In September of 2008, I was promoted to Manager of Cost of Service and in April of 2011 I was promoted to Senior Manager of Cost of Service. As Senior Manager of Cost of Service, I oversee the Company's cost-of-service activities such as power supply modeling, jurisdictional separation studies, class cost-of-service studies, and marginal cost studies.

Q. Please review the intent and design of the Power Cost Adjustment ("PCA") mechanism?

A. The PCA is a rate mechanism that quantifies and tracks annual differences between actual net power supply expenses ("NPSE") and the normalized level of NPSE recovered in the Company's base rates ("base level NPSE") for recovery or credit through an annual rate change each June 1. The PCA mechanism utilizes a 12-month test period of April through March ("PCA Year") and is composed of a forecast component ("PCA Forecast") and a true-up component ("PCA True-Up"). The PCA Forecast 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

PCA 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 any revenue sharing benefits resulting from the revenue sharing mechanism approved by Order No. 32424.

Q. What is the Company requesting in this case?

A. The Company is making three requests in this case. First, Idaho Power is requesting a determination by the Idaho Public Utilities Commission ("Commission") that the Company has correctly calculated new base rates in a manner that complies with Commission Order No. 33000 in Case No. IPC-E-13-20.[1] If the Company's calculation is

[1]Order No. 33000 approved a new normalized or base level NPSE of $305,684,869 to be utilized 1) to update base rates on June 1, 2014, and 2) as the basis for quantifying the 2014-2015 PCA rates that would also become effective June 1, 2014. The order also directed the Company to implement the change to base level NPSE in a manner that will have no net impact to the overall revenue collected through customer rates and is "revenue neutral" for all classes of Idaho customers.

approved, the newly established base rates will provide for collection of an additional $99.3 million in base level NPSE as directed in Order No. 33000. Second, the Company is requesting approval of the 2014-2015 PCA amount of $87.5 million, a decrease of approximately $72.1 million as compared to 2013-2014 PCA collection. If approved, the net effect of the change in base rates and the PCA would be an increase in annual billed revenue of approximately $27.1 million to become effective on June 1, 2014. Lastly, the Company is requesting that the Commission approve a one-time PCA mitigation measure intended to lessen the impact of this year's PCA on customers by utilizing $16 million of surplus Idaho Energy Efficiency Rider ("DSM Rider") funds as an offset to this year's PCA collection resulting in an adjusted net increase of approximately $11.1 million.

Q. Please provide an overview of the Company's case.

A. Mr. Scott Wright is the Company witness in this case who will present the development of the 2014-2015 PCA rates. Mr. Wright will explain that the methodology used to determine the 2014-2015 PCA rates is consistent with that approved by the Commission in prior PCA rate proceedings. Mr. Wright will also describe the changes to the PCA rate inputs that have occurred since last year's PCA. Finally, Mr. Wright will present for the Commission's approval an update to the rate listed on Schedule 89, Unit Avoided Energy Cost of Cogeneration and Small Power Production. The update to the Schedule 89 rate reflects the newly established base level NPSE as required by Order No. 32758.

My testimony in this case will present the quantification of the base rate increase pursuant to Order No. 33000 and describe the factors that have impacted this year's PCA quantification (including revenue sharing). Finally, my testimony will present the Company's rationale for proposing a one-time PCA mitigation measure intended to lessen the impact of this year's PCA on customers.

Q. How is your testimony organized?

A. My testimony is organized into seven sections. The first section presents the quantification of the base rate update pursuant to Order No. 33000 and details the implementation plan which will result in no net impact to the overall revenue collected through customer rates and will also be "revenue neutral" for all classes of Idaho customers. The second section provides a high-level discussion of the 2014-2015 PCA amount and the year-over-year differences that contribute to this year's PCA rate change. Beginning with the third section of my testimony, I will focus on individual components of the PCA. The third section provides a review of the factors that contributed to this year's true-up amount. The fourth section presents the determination of this year's revenue sharing amount. The fifth section describes the PCA forecast amount and the main drivers of that amount. In the sixth section of my testimony, I present a one-time PCA rate impact mitigation alternative for the Commission's consideration. The final section of my testimony summarizes the Company's request.

I. **<u>REVENUE NEUTRAL BASE RATE UPDATE</u>**

Q. Please provide a brief summary of the Commission's Order No. 33000 in Case No. IPC-E-13-20.

A. On March 21, 2014, the Commission issued Order No. 33000 approving the Company's request to establish a new normalized or base level NPSE of $305,684,869 to be utilized 1) to update base rates on June 1, 2014, and 2) as the basis for quantifying the 2014-2015 PCA rates that would also become effective June 1, 2014. The order also directed the Company to implement the change to base level NPSE in a manner that will have no net impact to the overall revenue collected through customer rates and is "revenue neutral" for all classes of Idaho customers. (Order No. 33000, p. 9.)

Q. How does the Company propose to implement the newly established base level NPSE of $305,684,869 to achieve a revenue neutral base rate adjustment?

A. The Company's request in this case includes a PCA determination based upon a measurement of the forecast April 2014 through March 2015 NPSE compared to the newly established 2013 base level NPSE of approximately $305.7 million. Because the new base level NPSE is greater than the previous base level NPSE, the resulting incremental PCA collection amount will be lower. Pursuant to Order No. 33000, the Company has quantified the base rate increase required to offset the reduction in incremental PCA collection on June 1, 2014. In other words, base rates are to be increased in a manner that will generate the same level of revenue that would have otherwise been allowed for recovery through the PCA.

Q. What is the difference between the previous base level NPSE and the newly established 2013 base level NPSE that will become effective on June 1, 2014, per Order No. 33000?

A. The difference between the previous base level NPSE and the newly established 2013 base level NPSE per Order No. 33000 that will become effective on June 1, 2014, is $105,691,091 on a total system-level. The following Table 1 presents on a detailed component basis the differences that exist on a total system-basis between the current base level NPSE and the 2013 base level NPSE that will become effective on June 1, 2014:

Table 1. System-Level PCA Accounts:

FERC Account	Current	Effective 6/1/14	Difference
	Base NPSE	Base NPSE	
Account 501, Coal	$ 167,192,744	$ 108,503,180	$ (58,689,564)
Account 536, Water for Power	1,828,640	2,380,597	551,957
Account 547, Other Fuel	51,934,201	33,367,563	(18,566,638)
Account 555, Purchased Power Non-PURPA	45,510,093	62,606,593	17,096,500
Account 565, 3rd Party Transmission	8,262,000	5,455,955	(2,806,045)
Account 447, Surplus Sales	(124,916,153)	(51,735,153)	73,181,000
Account 442, Hoku 1st Block	(23,921,466)	-	23,921,466
Net 95% Accounts	$ 125,890,059	$ 160,578,735	$ 34,688,676
Account 555, PURPA	$ 62,851,454	$ 133,853,869	$ 71,002,415
Account 555, Demand Response Incentives	11,252,265	11,252,265	-
Total	$ 199,993,778	$ 305,684,869	$ 105,691,091

Q. What is the Idaho jurisdictional share of the $105.7 million difference in system-level base NPSE?

A. Based upon the current energy-based allocation used for PCA computational purposes of 95.48 percent, the Idaho jurisdictional share of the $105.7 million difference in system-level base NPSE would be approximately $100.9 million.

Q. Does the $100.9 million represent the increase to Idaho jurisdictional base rates that the Company is proposing as part of this filing?

A. No. To maintain the same overall level of revenue recovery from base rates and the PCA in aggregate, it is necessary to adjust the $100.9 million difference in Idaho jurisdictional base level NPSE to reflect the 95/5 customer to Company sharing provision that exists in the

PCA. With the exception of 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.

As can be seen on Table 1, the total system-level difference in NPSE within the Federal Energy Regulatory Commission ("FERC") accounts that are subject to 95 percent recovery (or credit) under the PCA is approximately $34.7 million. Under the PCA mechanism, the Company would recover 95 percent of the Idaho jurisdictional share of the $34.7 million difference or $31.5 million ($34.7 million x 95.48% x 95.00% = $31.5 million). When the $31.5 million of allowed recovery is combined with 100 percent of the difference in the Idaho jurisdictional share of FERC Account 555, PURPA, of $67.8 million ($71.0 million x 95.48% = $67.8 million), the total allowed recovery under the PCA would be $99.3 million. Therefore, the Company's implementation of Order No. 33000 will result in an increase to base rates of approximately $99.3 million, which includes a $1.6 million "PCA sharing" reduction to the total difference in Idaho jurisdictional base level NPSE of $100.9 million. This $1.6 million "PCA sharing adjustment" will continue to be reflected in base rates until the Company files its next general rate case or it is otherwise adjusted by Commission order.

Q. Has the Company determined the new base rates in a manner that will be "revenue neutral" for all classes of customers as directed by Order No. 33000?

A. Yes. The Company has determined new base rates by apportioning the approximately $99.3 million base rate increase to each customer class using the same energy allocation basis that would exist under the PCA; that is, in proportion to each class's annual energy consumption. By using the same energy allocation basis applied in this year's PCA filing, each customer class will contribute exactly the same amount of revenue to offset NPSE that would exist under the PCA collection. Attached as Exhibit No. 1 to my testimony is a schedule which demonstrates that the Company's proposal would result in no change to the total amount of revenue by customer class from base rates and the PCA, in aggregate. As can be seen on Exhibit No. 1, a comparison of columns (D) and (H) demonstrates a revenue neutral shift of $99.3 million from the PCA into base rates.

Q. Are there any other steps that must be taken to ensure that the requested base rate increase is "revenue neutral" for all classes of Idaho customers?

A. Yes. 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, will result in approximately $4 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 million out of the DSM Rider balancing account and providing that amount as a credit to customers in the 2014-2015 PCA. This adjustment should continue to be included in future 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.

II. 2014-2015 PCA OVERVIEW

Q. What is the total 2014-2015 PCA amount as measured from the newly established 2013 base level NPSE for the 2014-2015 PCA Year?

A. The 2014-2015 total PCA amount (including revenue sharing and a $4 million DSM Rider adjustment) as measured from the newly established 2013 base level NPSE is $87.5 million. This represents a year-over-year reduction in PCA collection of $72.1 million when measured from the

2013-2014 PCA amount of $159.6 million. However, when combined with the base rate increase of $99.3, the total change in annual billed revenue would be an increase of approximately $27.1 million. The following Table 2 presents the year-over-year difference in billed revenue that would become effective June 1, 2014, segmented into the five components: 1) the PCA Forecast, 2) the PCA True-Up, 3) Revenue Sharing, 4) DSM Rider Transfer, and 5) Base Rate Adjustment.

Table 2. Billed Revenue Comparison:

Table 2: Billed Revenue Comparison (Idaho Jurisdictional Amounts)			
	2013-2014 PCA*	**2014-2015 PCA**	**Difference**
PCA Forecast	$111,969,107	$21,816,214	($90,152,893)
PCA True-Up	54,886,285	77,231,295	22,345,009
Revenue Sharing	(7,276,203)	(7,602,043)	(325,840)
DSM Rider Transfer	0	(3,970,276)	(3,970,276)
PCA Total	**$159,579,189**	**$87,475,190**	**($72,103,999)**
Base NPSE Update	0	99,250,892	99,250,892
Total	**$159,579,189**	**$186,726,081**	**$27,146,892**

* For comparison purposes, 2013-2014 PCA component amounts represent the Commission-approved 2013-2014 PCA rate applied to the June 2014 through May 2015 sales forecast

Q. Please describe the information contained in Table 2.

A. Table 2 demonstrates the extent to which each PCA and base rate component contributes to the year-over-year change in required revenue. As can be seen on Table 2, this year's PCA Forecast component is $21,816,214 which is $90,152,893 less than last year's PCA Forecast of

$111,969,107. This year's PCA True-Up component is $77,231,295. The difference between this year's PCA True-Up component and last year's PCA True-Up component is an increase of $22,345,009. This year's revenue sharing component is a credit of $7,602,043, which is $325,840 greater than last year's revenue sharing amount of $7,276,203. The "DSM Rider Transfer" that is necessary to ensure a revenue neutral implementation of the newly established base level NPSE is $3,970,276. Finally, when the base rate increase of $99,250,892 million is included, the net increase in total annual billed revenue is $27,146,892 million.

III. PCA TRUE-UP

Q. What is the most significant factor contributing to this year's PCA True-Up amount of approximately $77.2 million?

A. The most significant factor contributing to this year's PCA True-Up amount was lower actual hydro generation during the PCA Year as compared to the 2013-2014 forecasted amount. The lower actual hydro generation contributed to lower surplus energy sales revenue ("surplus sales"), which serves to offset power supply expenses recovered from customers.

In the 2013-2014 PCA Year, surplus sales were forecasted to be approximately $98.5 million. Actual surplus sales in the 2013-2014 PCA Year were approximately $66.8 million, or approximately 68 percent of the forecasted amount. Attached as Exhibit No. 2 to my testimony is a memo prepared at my direction that provides additional detail regarding the factors contributing to reduced surplus sales during the 2013-2014 PCA Year.

Q. How did actual hydro generation compare to the forecasted amount of hydro generation in the 2013-2014 PCA Year?

A. As can be seen on page 1 of Exhibit No. 2, hydro generation for the 2013-2014 PCA Year was forecast to be 6.8 million megawatt-hours ("MWh"). Actual hydro generation for the 2013-2014 PCA Year was 5.7 million MWhs, 1.1 million MWhs, or 16 percent, less than had been forecasted. The forecast of Brownlee Reservoir inflows for the 2013-2014 PCA Year included in last year's March Operating Plan was 9.42 million acre feet ("MAF"). Actual inflows for the PCA Year were 7.91 MAF, 16 percent lower than the forecasted amount. Detail regarding the Company's hydro generation for the 2013-2014 PCA Year is presented on page 2 of Exhibit No. 2.

Q. Were there any other factors that contributed to higher than projected NPSE during the 2013-2014 PCA Year?

A. Yes. Customer loads during the 2013-2014 PCA Year were higher than forecasted in the March 2013 Operating Plan by approximately one percent. Higher customer loads contributed to higher than forecasted power costs and lower surplus sales.

Q. To what extent did the True-Up of the True-Up contribute to this year's overall true-up balance?

A. Of the $77.2 million overall true-up balance, approximately $19.1 million is associated with the True-Up of the True-Up.

Q. What led to a True-Up of the True-Up balance of approximately $19.1 million?

A. As mentioned earlier in my testimony, the True-Up of the True-Up is the part of the PCA mechanism that tracks the collection of the prior year's true-up amount. Because collection of the PCA does not begin until June of each year, there is a two month lag between when the PCA rates are calculated based on March 31 balances and when collection/crediting actually begins in June. Therefore, when the PCA True-Up of the True-Up component of the PCA is developed, the balance only reflects approximately 10 months of collection. The impact of the lag in collection of the True-Up of the True-Up balance was compounded in this case because the 2012-2013 PCA True-Up component was a credit rate. As a result, revenue crediting rather than collection of the true-up balance was occurring during the billing months of April and May of 2013 also contributing to the True-Up of the True-Up balance.

In summary, this year's True-Up of the True-Up balance reflects the standard ten months of annual collection plus the impact of the revenue crediting that existed during the billing months of April and May of 2013 under the prior year's PCA rate.

Q. On April 2, 2013, the Commission issued Order No. 32776 (Case No. IPC-E-12-29) temporarily suspending two of three Idaho Power demand response programs for 2013. Did the suspension of the two demand response resources result in net benefits to customers?

A. Yes.

Q. Have you quantified the savings associated with the reduction in the incentive payments to the program participants?

A. Yes. Idaho Power estimates that the two temporarily suspended programs reduced program incentive expenses by more than $10.0 million. The reduced demand response program incentive costs were reflected in the 2013/2014 PCA Forecast.

Q. Did the Company incur additional power supply expenses in order to obtain the $10.0 million in incentive payment reductions?

A. Yes, but only to a very limited extent. Idaho Power estimates that it incurred additional power supply expenses of less than $10,000 associated with the suspension of the two programs. Therefore, the suspension of the two demand response programs in 2013 resulted in a net benefit to customers of nearly $10.0 million dollars.

IV. REVENUE SHARING

Q. What impact does revenue sharing have on this year's PCA?

A. The Company's 2013 Idaho jurisdictional earnings were at a level that provides for approximately $7.6 million in direct benefits to customers as part of this year's PCA. This represents an increase in the level of sharing of approximately $326 thousand as compared to last year's sharing amount.

Q. What is the total benefit customers will receive as a result of revenue sharing based on the Company's actual year-end 2013 financial results?

A. After tax gross-up, the combination of a $7,602,043 reduction to PCA rates and a $16,512,853 reduction to the pension balancing account results in an overall customer benefit of $24,114,895.

Q. Have you prepared an exhibit that details the Company's quantification of the Idaho jurisdictional 2013 Return on Equity ("ROE") and year-end earnings in excess of 10 percent?

A. Yes. Exhibit No. 3 details the Company's quantification of the Idaho jurisdictional 2013 ROE and year-end earnings in excess of 10 percent. As can be seen on line 46 of Exhibit No. 3, the 2013 Idaho jurisdictional ROE was 11.22 percent. As quantified on line 73 of Exhibit No. 3, in 2013, the Company's earnings exceeded an Idaho jurisdictional year-end ROE of 10 percent by $22,668,223.

Q. How did the Company determine the portion of the $22,668,223 that is to be shared with customers?

A. In accordance with the terms of the settlement stipulation approved in Order No. 32424, revenue sharing based on year-end 2013 financial results is to be provided to customers in two tiers. The first tier reflects customers' 50 percent share of the 2013 Idaho jurisdictional year-end earnings in excess of 10 percent ROE up to and including 10.5 percent. The first tier, calculated at 50 percent of $9,259,492, results in a customer benefit prior to tax gross-up of $4,629,746. After tax gross-up, customers receive a total rate reduction of $7,602,043. These amounts are displayed in Exhibit No. 3 on line 69.

The second tier reflects customers' 75 percent share of the 2013 Idaho jurisdictional year-end earnings in excess of 10.5 percent ROE. The second tier, calculated at 75 percent of $13,408,731, results in a customer benefit prior to tax gross-up of $10,056,549. After tax gross-up, customers receive a total benefit of $16,512,853 in the form of an offset to the Company's pension balancing account. These amounts are displayed in Exhibit No. 3 on line 71. An accounting entry was made to reduce the pension deferral balancing account by $16,512,853 with an effective date of December 31, 2013, to reflect this benefit.

Q. How does the Company propose to allocate the $7,602,043 revenue sharing to customer classes?

A. The Company proposes to allocate the $7,602,043 revenue sharing as a rate reduction to customer classes based on each class's proportional share of the forecasted base revenues for the June 1, 2014, through May 31, 2015, sharing period. This is the same methodology used to allocate the revenue sharing in 2011 and 2012.

Q. What is the impact of allocating the proposed rate reduction to customer classes proportionally to base revenues?

A. As displayed in column G of Exhibit No. 4, each customer class receives a decrease of approximately 0.76 percent relative to current base revenues.

Q. How does the Company propose to include the class-allocated revenue sharing benefits in rates?

A. With the exception of the Special Contracts for Micron, the U.S. Department of Energy, and J.R. Simplot, Inc. ("Special Contracts"), the Company proposes to include the class-allocated revenue sharing benefits as an offset to the 2014 PCA rates effective June 1, 2014, through May 31, 2015, as detailed in this case by Mr. Scott Wright. Column F of Exhibit No. 4 details the proposed class-specific revenue sharing rates I have provided to Mr. Wright to be included as an offset in the 2014 PCA rates.

Q. What is the Company's proposal for providing revenue sharing benefits to its Special Contracts?

A. Consistent with the methodology used to share 2011 and 2012 revenues, the Company proposes to provide the Special Contracts a flat dollar-per-month credit in twelve equal portions to serve as an offset to monthly invoices billed for June 2014 through May 2015.

V. PCA FORECAST

Q. How does the Company's forecast of NPSE for the 2014-2015 PCA compare to the forecast in last year's PCA?

A. The PCA Forecast on a total system basis for the 2014-2015 PCA Year is $330,026,256, which is $10,521,190 higher than last year's PCA Forecast of $319,505,066. Table 3 presents a comparison of this year's PCA Forecast to last year's PCA Forecast by PCA component on a total system basis.

Table 3. PCA Forecast Comparison:

Table 3: PCA Forecast Comparison (Total System-Level)			
	2013-2014 Forecast	2014-2015 Forecast	Difference
Coal	$ 165,951,392	$ 169,424,879	$ 3,473,487
Water for Power	2,354,374	1,751,000	(603,374)
Gas	66,536,064	73,941,673	7,405,609
Non-PURPA	40,080,534	61,996,853	21,916,319
3rd Party Transmission	6,692,385	6,645,775	(46,610)
Hoku First Block	-	-	-
Surplus Sales	(98,510,169)	(126,166,913)	(27,656,744)
Net 95% accounts	$ 183,104,580	$ 187,593,267	$ 4,488,687
PURPA	$ 131,731,526	$ 134,142,386	$ 2,410,860
Demand Response Incentive	4,668,960	8,290,603	3,621,643
100% accounts	$ 136,400,486	$ 142,432,989	$ 6,032,503
Total PCA Forecast	$ 319,505,066	$ 330,026,256	$ 10,521,190

Q. What are the main factors contributing to the increase in the PCA Forecast this year?

A. As can be seen in Table 3, Coal and Gas production costs are expected to increase from last year's forecast by a combined $10.9 million. That increase is expected to be offset by decreases in Water for Power expense and Third Party Transmission expense as well as an increase in net Surplus Sales. The combined increase in the expense categories under which Idaho Power is allowed 95 percent recovery of deviations from base level NPSE is approximately $4.5 million.

PURPA and Demand Response Incentive expenses are expense categories under which Idaho Power is allowed 100 percent recovery of deviations from base level NPSE. These two expense categories combined account for almost 60 percent of the increase over last year's forecast or approximately $6.0 million.

Q. What is driving the increase in Demand Response Incentive expenses?

A. The increase is due to increased incentive payments associated with the A/C Cool Credit and Irrigation Peak Rewards programs that will be operational again in 2014 as a result of the settlement agreement approved by Order No. 32923. Based on enrollment as of April 7, 2014, Idaho Power expects 392 megawatts of demand response load reduction at the generation level for the 2014 season.

Q. Recent reports suggest near normal snow pack for the basins above the Brownlee Reservoir. Based on the status of this year's snow pack conditions, is Idaho Power expecting near normal hydro production?

A. Unfortunately, no. The Company's expectation for hydro production included in the March 2013 Operating

Plan is not materially different from last year's hydro production forecast. The Company is forecasting 6.9 million MWhs of hydro generation for the 2014-2015 PCA Year, nearly the same as last year's forecast of 6.8 million MWhs. The 30-year average annual hydro generation for Idaho Power's system is approximately 8.0 million MWhs placing the 2014-2015 PCA forecast of hydro generation at about 86 percent of the normal expectation. The 2014-2015 PCA hydro generation forecast is based on projected Brownlee inflow volumes of 3.6 MAF for April through July and 8.8 MAF for the PCA Year of April 2014 through March 2015. The historical 30-year averages for the same periods are 5.5 MAF and 13.1 MAF, respectively. The lower anticipated hydro generation will contribute to increased coal and gas production costs and lower surplus sales revenue as compared to normal levels.

Q. If snowpack levels in the basins above the Brownlee Reservoir are at or near normal levels, then why is the Company expecting lower than normal hydro generation?

A. The hydro generation forecast for the 2014-2015 PCA Year is impacted primarily by the persistent dry weather conditions that occurred during 2013 and through January 2014. The impacts of these dry conditions to the hydro generation forecast include significantly low upstream reservoir levels, considerable reductions in irrigation returns impacting reach gains, and continued dry soil conditions in parts of the Snake River Basin.

Federal reservoirs in the Upper Snake, Payette, and Boise basins greatly impact the magnitude and timing of flows to Idaho Power's hydro system. At the beginning of this water year, October 1, 2013, the major federal reservoirs above Brownlee were at 38 percent of normal storage. This carryover storage level would rank as the fifth lowest when compared to the 1981-2010 period. In order to refill from the low carryover storage level, the reservoirs would require significantly above normal snowpack, measured in terms of snow water equivalent ("SWE"). When the upstream reservoirs fail to refill, Idaho Power, along with all other downstream water users, are likely to experience below normal reservoir releases. The late season precipitation over the recent months has greatly improved the forecast for projected releases from upstream reservoir systems, but the inflow forecast remains below normal. Detail regarding these events and their impact on the Company's forecast hydro generation is presented on pages 2-4 of Exhibit No. 2.

VI. IDAHO POWER'S PCA MITIGATION ALTERNATIVE

Q. Did the Company evaluate potential options to mitigate the impact of this year's PCA on customer rates?

A. Yes. The Company believes it would be appropriate for the Commission to consider allowing a one-time transfer of an additional $16 million from the DSM Rider balancing account to offset this year's PCA. This action would result in a total transfer of $20 million of DSM Rider funds into this year's PCA.

Q. What is the Company's rationale for this proposal?

A. Idaho Power's current level of DSM Rider collection is four percent of base rate revenues or approximately $36 million annually. The June 1, 2014, DSM Rider balance is expected to be a surplus of about $12.2 million. DSM Rider-funded expenses are forecasted to be approximately $20 million per year on average over the next two years. Without the proposed one-time transfer, the DSM Rider balance is forecasted to be a surplus of $26 million by May 31, 2015, and Idaho Power expects to continue to accumulate a surplus of energy efficiency funding in the near-term. In order to mitigate the customer impact of the requested PCA increase, Idaho Power is proposing a one-time transfer of $16 million of surplus DSM Rider funds back to customers through the PCA.

Q. How does the Company propose to allocate the $16 million DSM Rider transfer to individual customer classes?

A. The Company proposes to allocate the $16 million DSM Rider transfer to individual customer classes as a rate reduction based on each class's proportional share of the forecasted base revenues for the June 1, 2014, through May 31, 2015, PCA collection period. This allocation method will ensure that each customer class receives the PCA rate credit in a similar proportion to the initial DSM Rider collection.

Q. What are the benefits associated with Idaho Power's proposal for a transfer of surplus DSM Rider funds to offset this year's PCA?

A. In addition to providing immediate rate relief, the Company believes that a one-time transfer of DSM Rider funds will help to manage the DSM Rider balance in the near-term without impacting the longer-term level of funding provided by the DSM Rider.

Q. What would be the impact to the DSM Rider balance if the Commission were to approve the Company's PCA mitigation proposal?

A. A transfer of $20 million in DSM Rider funds to offset the PCA would bring the DSM Rider balance to an estimated surplus of $9.8 million at May 31, 2015. The

Company believes that customers would prefer a rate credit in this year's PCA rather than Idaho Power holding on to funds that are not expected to be used in the next few years.

Q. You stated that the transfer of $20 million in DSM Rider funds includes the $4 million of DSM Rider funds associated with the increase in base rate revenues effective June 1, 2014. Does the Company believe that the $4 million transfer should continue in future PCAs?

A. Yes. In order to maintain a "revenue neutral" rate adjustment, the Company believes that it would be appropriate to transfer $4 million each year from the DSM Rider balance to serve as an offset to the PCA until the next general rate case.

Q. How will the additional one-time transfer of $16 million from DSM Rider funds to the PCA impact the Company's energy efficiency activities?

A. A total transfer of $20 million in surplus DSM Rider funds will have no impact on existing or new energy efficiency activities. Idaho Power will continue to offer a full portfolio of energy efficiency programs for all customer sectors. Regardless of the DSM Rider's balance, the Company is committed to energy efficiency initiatives and pursing all cost-effective energy efficiency.

Q. What impact will the total $20 million transfer of DSM Rider funds have on the DSM Rider balancing account in the near-term?

A. As I mentioned earlier, the DSM Rider balance is expected to be approximately $12.2 million on June 1, 2014. Even with the transfer of $20 million and forecasted energy efficiency expenses, Idaho Power estimates the DSM Rider balancing account will be in a collected status again by September 2014. By managing the DSM Rider balance today, no changes to the level of DSM Rider fund collection are being recommended at this time.

Q. You indicated the DSM Rider balance will be a deficit for three months, in June, July, and August 2014. Will customers pay an additional interest charge on the deficit balance for those months?

A. No, not on a net basis. The current deposit rate used to calculate the annual carrying charge on deferred balances, which includes both the DSM Rider balancing account and the PCA, is one percent. Although customers will pay interest on the DSM Rider deficit balance for three months, the DSM Rider funds transferred to the PCA will reduce the amount of interest that would accrue on the PCA balance by the same amount, resulting in a net change of zero in the amount of interest customers would pay.

Q. Has the Company shared its planned proposal to transfer funds from the DSM Rider to offset this year's PCA balance with external stakeholders?

A. Yes. On Monday, March 17, 2014, Idaho Power held a conference call with its Energy Efficiency Advisory Group ("EEAG") to inform EEAG members that the Company was considering using DSM Rider funds to achieve a revenue neutral implementation of the new base level NPSE and to possibly mitigate the impact on customers of a PCA increase. The Company also solicited feedback from the EEAG members regarding the proposal as part of the call.

In this call, the Company informed the EEAG that, if the Commission approved Idaho Power's request to set a new level of net power supply expense, base rate revenue would increase by approximately $100 million, resulting in an additional $4 million (approximate) per year in DSM Rider revenue (4 percent x $100 million = $4 million). In this event, the Company planned to request authority to transfer $4 million out of the DSM Rider balancing account and provide that amount as a uniform rate credit in the 2014-2015 PCA, thus keeping the net power supply expense filing revenue neutral for customers.

The Company also shared with the EEAG that, if the PCA was an increase, the Company was considering a one-time transfer of additional DSM Rider funds to the PCA, which would reduce the impact of the PCA on customers.

Q. What was the overall sentiment from the EEAG members regarding the transfer of funds from the DSM Rider to mitigate the PCA balance?

A. Of the participating members who attended the telephonic meeting, there were several clarifying questions asked, some concerns expressed, as well as comments of support. EEAG members also expressed gratitude for the company bringing this concept to their attention and the opportunity to discuss the issue.

Q. What is the adjusted billed revenue impact that would result from applying the Company's PCA mitigation alternative?

A. Should the Commission wish to apply the mitigation adjustment presented by the Company, this year's net increase in billed revenue would be reduced from $27.1 million to $11.1 million, as presented in Table 4 below. The $11.1 million represents an overall increase of approximately 1.0 percent over current billed revenue.

Table 4. Updated Billed Revenue Comparison:

Table 4: Billed Revenue Comparison (Idaho Jurisdictional Amounts)			
	2013-2014 PCA*	**2014-2015 PCA**	**Difference**
PCA Forecast	$111,969,107	$21,816,214	($90,152,893)
PCA True-Up	54,886,285	77,231,295	22,345,009
Revenue Sharing	(7,276,203)	(7,602,043)	(325,840)
DSM Rider Transfer (Ongoing)	0	(3,970,276)	(3,970,276)
DSM Rider Transfer (One-time)	0	(16,029,724)	(16,029,724)
PCA Total	**$159,579,189**	**$71,445,466**	**($88,133,724)**
Base NPSE Update	0	99,250,892	99,250,892
Total	**$159,579,189**	**$170,696,357**	**$11,117,168**

*For comparison purposes, 2013-2014 PCA component amounts represent the Commission-approved 2013-2014 PCA rate applied to the June 2014 through May 2015 sales forecast

Q. Why should the Commission consider approving the Company's mitigation alternative in this case?

A. It is my belief that when the Commission has considered PCA mitigation in the past it has tried to balance the impact that any mitigation may have on the financial health of Idaho Power with a desire to maintain fair rates and rate stability. The Company believes that its mitigation proposal would have no financial impact on the Company and would also satisfy the Commission's desire to maintain fair rates and rate stability. The Company's proposed PCA mitigation alternative would simply utilize surplus customer funds from the DSM Rider balancing account to offset excess power costs in this year's PCA. Unlike other PCA mitigation options considered by the Commission in the past, this approach would not defer any PCA collection to a subsequent period, but rather would use funds already collected from customers to offset currently known costs.

VII. CONCLUSION

Q. Please summarize the Company's request in this case?

A. Idaho Power is requesting that the Commission issue an Order that 1) approves the Company's calculation of new base rates resulting in approximately $99.3 million of additional base rate recovery of net power supply expense annually in compliance with Order No. 33000, 2) approves the 2014-2015 PCA recovery amount of approximately $87.5 million, as the measured deviation from newly established base rates, resulting in a net increase in annual billed revenue of approximately $27.1 million, and 3) approves a one-time PCA mitigation measure intended to lessen the impact of this year's PCA on customers by utilizing an additional $16 million of surplus DSM Rider funds to offset this year's PCA collection resulting in an adjusted net increase of approximately $11.1 million to become effective June 1, 2014.

Q. Has the Company prepared revised tariff schedules that present the updated base rates and PCA rates that would result from applying the Company's mitigation alternative?

A. Yes. Attachment 1 to the Application is revised tariff schedules, in both clean and legislative formats, specifying the proposed base rate and PCA rate changes for providing electric service to customers in the state of Idaho with a net change of $11.1 million in total billed revenue to be collected during the 2014-2015 PCA Year.

Q. Does this conclude your testimony?

A. Yes, it does.

ATTESTATION OF TESTIMONY

STATE OF IDAHO)
) ss.
County of Ada)

I, Timothy E. Tatum, 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 Senior Manager 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.

Timothy E. Tatum

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

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

KIMBERLY K. TOWELL
NOTARY PUBLIC
STATE OF IDAHO

KIMBERLY K. TOWELL
NOTARY
PUBLIC
STATE OF IDAHO

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-14-05

IDAHO POWER COMPANY

TATUM, DI
TESTIMONY

EXHIBIT NO. 1

Idaho Power Company
Calculation of Revenue Impact
NPSE/PCA Summary
State of Idaho
Filed April 15, 2014

Line No	Tariff Description	Rate Sch. No.	(A) Average [1] Number of Customers	(B) Normalized [1] Energy (kWh)	(C) Current Base Revenue	(D) NPSE Adjustments to Base Revenue	(E) Base Revenue Effective June 1, 2014	(F) PCA Before [2] Base Adjustment	(G) PCA After [2] Base Adjustment	(H) PCA Reduction Due to NPSE Base Adjustment
	Uniform Tariff Rates:									
1	Residential Service	1	412,772	4,905,224,592	$ 411,592,160	$ 35,906,244	$ 447,498,404	$ 71,738,910	$ 35,832,666	$ (35,906,244)
2	Master Metered Mobile Home Park	3	23	4,983,593	394,984	36,480	431,464	72,885	36,405	(36,480)
3	Residential Service Time-of-Day	5	1,483	26,868,737	2,143,865	196,679	2,340,544	392,955	196,276	(196,679)
4	Small General Service	7	28,078	143,241,424	15,298,850	1,048,527	16,347,378	2,094,906	1,046,379	(1,048,527)
5	Large General Service - Secondary	9S	33,046	3,164,200,200	192,062,186	23,161,945	215,224,132	46,276,428	23,114,482	(23,161,945)
6	Large General Service - Primary	9P	203	462,178,285	23,972,684	3,383,145	27,355,829	6,759,357	3,376,212	(3,383,145)
7	Large General Service - Transmission	9T	3	2,426,064	130,560	17,759	148,319	35,481	17,722	(17,759)
8	Dusk to Dawn Lighting	15	0	6,399,685	1,227,944	46,846	1,274,790	93,595	46,750	(46,846)
9	Large Power Service - Secondary	19S	1	6,349,085	326,761	46,475	373,236	92,855	46,380	(46,475)
10	Large Power Service - Primary	19P	106	2,119,873,345	95,632,247	15,517,473	111,149,720	31,003,148	15,485,675	(15,517,473)
11	Large Power Service - Transmission	19T	2	33,704,165	1,456,070	246,714	1,702,784	492,923	246,209	(246,714)
12	Agricultural Irrigation Service	24	17,415	1,752,403,245	116,644,400	12,827,592	129,471,992	25,628,897	12,801,306	(12,827,592)
13	Unmetered General Service	40	1,296	12,162,729	901,646	89,031	990,677	177,880	88,849	(89,031)
14	Street Lighting	41	1,344	26,964,987	3,241,072	197,384	3,438,456	394,363	196,979	(197,384)
15	Traffic Control Lighting	42	454	2,826,554	142,204	20,690	162,894	41,338	20,648	(20,690)
16	Total Uniform Tariffs		496,226	12,669,806,690	$ 865,167,633	$ 92,742,985	$ 957,910,618	$ 185,295,923	$ 92,552,938	$ (92,742,985)
17	Special Contracts									
18	Micron	26	1	466,006,690	$ 18,089,440	$ 3,411,169	$ 21,500,609	$ 6,815,348	$ 3,404,179	$ (3,411,169)
19	J R Simplot	29	1	186,125,488	6,829,907	1,362,439	8,192,346	2,722,085	1,359,647	(1,362,439)
20	DOE	30	1	236,926,098	8,868,760	1,734,299	10,603,060	3,465,044	1,730,745	(1,734,299)
21	Total Special Contracts		3	889,058,276	$ 33,788,108	$ 6,507,907	$ 40,296,014	$ 13,002,477	$ 6,494,571	$ (6,507,907)
22	Total Idaho Retail Sales		496,229	13,558,864,966	$ 898,955,741	$ 99,250,892	$ 998,206,633	$ 198,298,400	$ 99,047,509	$ (99,250,892)

Note:
(1) June 1, 2014 - May 31, 2015, Forecast
(2) Excludes Revenue Sharing and DSM Rider Transfer

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-14-05

IDAHO POWER COMPANY

TATUM, DI
TESTIMONY

EXHIBIT NO. 2

Date: April 11, 2014

To: Tim Tatum, Cost of Service Manager

From: Philip DeVol, Resource Planning Leader

Subject: 2013-2014 Surplus Sales Forecast Compared to Actual
2014-2015 Surplus Sales Forecast

This memo is intended to address the variances between the 2013-2014 PCA forecast and the actual amounts for both the hydro generation and surplus sales components of the PCA, and to provide an explanation for the 2014-2015 PCA forecast.

2013-2014 Surplus Sales Forecast Compared to Actual

The differences between forecasted and actual amounts are shown below.

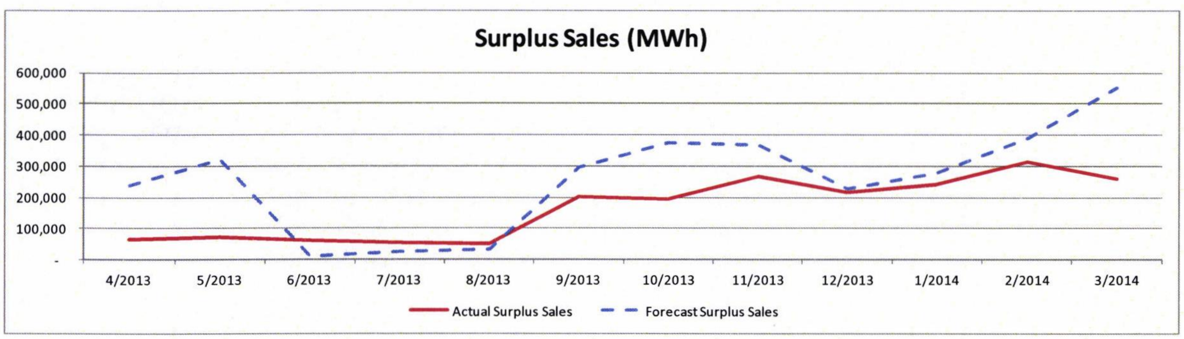
	Forecast	Actual	Variance
Hydro Generation (000s MWh)	6,826	5,702	1,124
Surplus Sales (000s MWh)	3,115	1,998	1,117
Surplus Sales (000s of dollars)	98,510	66,785	31,725

Surplus Sales

Surplus sales were impacted primarily by lower hydro generation. Surplus sales were also impacted by lower production at Langley Gulch power plant, particularly during October 2013 and March 2014. However, these sales were mostly offset by decreased Langley Gulch fuel costs, resulting in a minimal overall impact to the PCA. The dollar variance (in thousands of dollars) is shown by month in the table below. The graph below the table further demonstrates the variance of forecasted MWh sales volume as compared to actual MWh sales volume by month.

Surplus Sales (000s of dollars)

	4/2013	5/2013	6/2013	7/2013	8/2013	9/2013	10/2013	11/2013	12/2013	1/2014	2/2014	3/2014	Total
Forecast	6,054	6,643	394	911	1,040	9,935	12,213	12,118	8,361	10,248	14,174	16,420	98,510
Actual	1,442	1,224	1,450	2,398	2,032	6,426	6,225	9,126	7,452	8,385	9,811	10,814	66,785
Variance	(4,611)	(5,420)	1,057	1,487	992	(3,509)	(5,988)	(2,992)	(910)	(1,862)	(4,363)	(5,606)	(31,725)
Percentage	-76%	-82%	268%	163%	95%	-35%	-49%	-25%	-11%	-18%	-31%	-34%	-32%



Two months requiring special explanation are October 2013 and March 2014. For both months, the 2013-2014 PCA forecast included the full dispatch of Langley Gulch in support of surplus sales. However, the plant ultimately was not dispatched in October 2013 due to required maintenance and was not dispatched in March 2014 due to lower market prices. While surplus sales for the two months were impacted by the lower than forecast production from Langley Gulch, the impact on the overall PCA was minimal because of a corresponding decrease in Langley Gulch fuel expense.

With the exception of October 2013 and March 2014, the lower than forecast surplus sales are primarily explained by a decline in hydro generation.

Hydro Generation

Actual hydro generation was lower than anticipated in almost every month and for the PCA year was nearly 1.1 million MWh, or 16 percent, lower than forecast. Hydro generation is directly related to Brownlee Reservoir inflow, which was also lower than forecast in nearly every month and for the PCA year was 1.5 million acre-feet (MAF), or 16 percent, lower than forecast. The following tables show hydro generation and Brownlee inflow by month.

Hydroelectric Generation (000s MWh)

	4/2013	5/2013	6/2013	7/2013	8/2013	9/2013	10/2013	11/2013	12/2013	1/2014	2/2014	3/2014	Total
Forecast	558	781	686	525	514	491	431	412	497	587	551	793	6,826
Actual	456	560	483	506	419	431	453	396	442	425	436	695	5,702
Variance	102	221	203	19	94	61	(22)	16	55	162	115	98	1,124
Percentage	-18%	-28%	-30%	-4%	-18%	-12%	5%	-4%	-11%	-28%	-21%	-12%	-16%

Brownlee Inflow (MAF)

	4/2013	5/2013	6/2013	7/2013	8/2013	9/2013	10/2013	11/2013	12/2013	1/2014	2/2014	3/2014	Total
Forecast	0.92	1.16	1.00	0.56	0.57	0.57	0.68	0.73	0.71	0.68	0.74	1.09	9.42
Actual	0.66	0.86	0.63	0.45	0.48	0.60	0.68	0.64	0.63	0.62	0.71	0.94	7.91
Variance	(0.26)	(0.29)	(0.37)	(0.11)	(0.09)	0.02	(0.00)	(0.08)	(0.08)	(0.07)	(0.03)	(0.15)	(1.51)
Percentage	-28%	-25%	-37%	-20%	-16%	4%	0%	-11%	-11%	-10%	-4%	-14%	-16%

2014-2015 Hydro Generation Forecast

The hydro generation forecast for the 2014-2015 PCA year is 6.9 million MWh. The hydro generation forecast for the 2014-2015 PCA year is impacted primarily by the persistent dry weather conditions that occurred during 2013 and through January 2014. The impacts of these dry conditions to the hydro generation forecast include significantly low upstream reservoir levels, considerable reductions in irrigation returns impacting reach gains, and continued dry soil conditions in parts of the Snake River Basin. A discussion of these impacts follows.

Reservoir Levels

Federal reservoirs in the Upper Snake, Payette, and Boise basins greatly impact the magnitude and timing of flows to Idaho Power's hydro system. In a normal year, the company's hydro system generates with flow releases from these reservoir systems associated with the company's primary storage right in American Falls Reservoir, federal flow augmentation to aid downstream salmon outmigration, and flood control. In addition, Idaho Power currently has a contract agreement in place to release water leased from the Shoshone-Bannock Tribal Water Supply Bank. The volume of these releases is directly related to the amount of reservoir storage.

At the beginning of this water year, October 1, 2013, the major federal reservoirs above Brownlee were at 38 percent of normal storage. This carryover storage level would rank as the fifth lowest when compared to the 1981-2010 period. In order to refill from the low carryover storage level, the reservoirs would require significantly above normal snowpack, measured in terms of snow water equivalent (SWE). When the upstream reservoirs fail to refill, Idaho Power, along with all other downstream water users, risk below normal reservoir releases.

Precipitation during the snow accumulation months of November through January ranked the 15th lowest of the 119 years of record for the state of Idaho. The estimated weighted SWE above Brownlee Reservoir on January 31, 2014, was at 9.7 inches, or 72 percent of normal, and major federal reservoirs above Brownlee were at 65 percent of normal storage. February and March precipitation was normal or above normal for much of the region, improving the Brownlee SWE to 22.2 inches, or 109 percent of normal, and major federal reservoir levels rose to 80 percent of normal storage. The table below shows the combined reservoir storage for the major federal reservoirs above Brownlee and the estimated weighted SWE above Brownlee Reservoir at three critical dates: the beginning of the water year, January 31, 2014, and March 31, 2014.

	Reservoir Storage at Major Reservoirs Above Brownlee			**SWE at Brownlee**		
	Actual (MAF)	**Normal (MAF)**	**Percent of Normal**	**Actual (inches)**	**Normal (inches)**	**Percent of Normal**
October 1, 2013	1.05	2.74	38%	0	0	0
January 31, 2014	2.44	3.73	65%	9.7	13.5	72%
March 31, 2014	3.45	4.30	80%	22.2	20.3	109%

This late season precipitation greatly improved the forecast for projected releases from upstream reservoir systems, but the inflow forecast remains below normal. The PCA forecast was prepared near the end of March and incorporated the latest information from Idaho Power's own models, including the most current snowpack and soil conditions, projected upstream reservoir releases, and forecasted irrigation demand. The March flow forecast included upstream reservoir releases for all of the company's primary storage right at American Falls Reservoir, 93 percent of federal flow augmentation for salmon outmigration, and 75 percent of the full Shoshone-Bannock water lease. The March forecast also assumes no flood control releases from the Upper Snake River basin past Milner Dam, since any additional water will be captured by American Falls and Palisades Reservoirs. However, the forecast does include some flood control releases from the Boise and Payette basins. The table below shows the progression of the forecast assumptions over the course of the water year as compared to normal water year assumptions.

	Forecast Assumptions (Percent of Normal)		
	Primary Storage	**Flow Augmentation**	**Leased Water**
October 1, 2013	100%	65%	25%
January 31, 2014	100%	47%	25%
March 31, 2014	100%	93%	75%

Continued Dry Soil Conditions and Decreased Irrigation Returns

Although the amount of precipitation that fell throughout the basin during February and March 2014 was significantly above average, the amount of precipitation from the beginning of the water year in October remains below normal. This is most apparent in the southern tributaries as well as the lower elevations throughout the basin. The impact of low overall precipitation is that soil conditions throughout the Snake Basin remain low, affecting the forecasted amount of subsurface flow and snowpack runoff entering the river system.

Due to the significantly dry conditions throughout the basin during the 2013 irrigation season, irrigators more efficiently managed their water supplies to utilize less water. Growing seasons were shortened, modifications to sprinkler heads were made to make systems more efficient, and monitoring equipment was installed in some areas of the basin. The result to the hydro generations forecast is that irrigation return flows back to the river during subsequent months has been and is projected to continue to be greatly reduced. This reduction in irrigation return flows is currently reflected in the 2014-2015 hydro generation forecast.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-14-05

IDAHO POWER COMPANY

TATUM, DI
TESTIMONY

EXHIBIT NO. 3

IDAHO POWER COMPANY

ADDITIONAL INVESTMENT TAX CREDIT ANALYSIS
For the Twelve Months Ended December 31, 2013

Line		Actual September 30, 2013			Actual December 31, 2013		
		TOTAL SYSTEM	IDAHO	IDAHO %	TOTAL SYSTEM	IDAHO	IDAHO %
9	****** SUMMARY OF RESULTS ******						
10	TOTAL COMBINED RATE BASE	2,901,610,428	2,781,439,627	95.9%	September Allocations/Ratios		
11							
12	DEVELOPMENT OF NET INCOME				Update figures in RED		
13	OPERATING REVENUES						
14	RETAIL SALES REVENUES (Incl 449.1 Rev)	852,279,026	812,821,840	Direct Assign	1,109,330,208	1,057,998,566	Direct Assign
15	OTHER OPERATING REVENUES	100,732,831	96,800,192	96.1%	140,422,703	134,940,560	96.1%
16	TOTAL OPERATING REVENUES	953,011,857	909,622,032		1,249,752,911	1,192,939,126	
17							
18	OPERATING EXPENSES						
19	OPERATION & MAINTENANCE EXPENSES	563,941,726	534,440,756	94.8%	762,469,304	722,582,941	94.8%
20	DEPRECIATION EXPENSE	91,138,716	87,333,709	95.8%	122,073,203	116,976,693	95.8%
21	AMORTIZATION OF LIMITED TERM PLANT	5,467,478	5,244,936	95.9%	7,571,050	7,262,886	95.9%
22	TAXES OTHER THAN INCOME	23,242,609	21,610,259	93.0%	30,560,823	28,414,508	93.0%
23	REGULATORY DEBITS/CREDITS	42,132	0	0.0%	56,176	0	0.0%
24	PROVISION FOR DEFERRED INCOME TAXES	46,297,181	44,562,002	96.3%	65,218,600	62,774,262	96.3%
25	INVESTMENT TAX CREDIT ADJUSTMENT	(524,128)	(502,605)	95.9%	(775,313)	(743,476)	95.9%
26	FEDERAL INCOME TAXES	20,853,067	20,749,033	99.5%	9,918,700	9,869,216	99.5%
27	STATE INCOME TAXES	4,445,665	4,367,369	98.2%	5,499,764	5,402,902	98.2%
28	TOTAL OPERATING EXPENSES	754,904,449	717,805,458		1,002,592,306	952,539,932	
29							
30	OPERATING INCOME	198,107,408	191,816,574		247,160,605	240,399,194	
31	ADD: IERCO OPERATING INCOME	4,827,703	4,616,496	95.6%	6,704,329	6,411,022	95.6%
32							
33	OPERATING INCOME BEFORE OTHER INCOME & DEDUCTIONS	202,935,111	196,433,070		253,864,934	246,810,216	97.2%
34	ADD: AFUDC EQUITY				14,857,580	14,242,250	95.9% (L 10)
35	ADD: OTHER INCOME AND DEDUCTIONS				3,359,652	3,266,289	97.2% (L 33)
36							
37	INCOME BEFORE INTEREST CHARGES				272,082,165	264,318,755	
38	LESS: INTEREST CHARGES				80,653,845	77,313,549	95.9% (L 10)
39							
40	NET INCOME				191,428,320	187,005,206	
41							
42	ACTUAL YEAR-END RESULTS - BEFORE ITC ADJUSTMENT						
43	EARNINGS ON COMMON STOCK				191,428,320	187,005,206	
44	COMMON EQUITY AT YEAR END				1,738,717,851	1,666,708,489	95.9% (L10)
45							
46	RETURN ON YEAR-END COMMON EQUITY				11.01%	11.22%	
47							
48	EARNINGS ON COMMON STOCK @ 9.50 ROE				165,178,196	**158,337,306**	(L44 * 9.5%)
49	EARNINGS ON COMMON STOCK @ 10 ROE				173,871,785	**166,670,849**	(L44 * 10%)
50	EARNINGS ON COMMON STOCK @ 10.50 ROE				182,565,374	**175,004,391**	(L44 * 10.5%)
51							
52							
53	ACTUAL YEAR-END RESULTS - AFTER ITC ADJUSTMENT:						
54	INVESTMENT TAX CREDIT ADJUSTMENT					(31,677,237)	(L48-L43) / (1-9.5%)
55	ADJUSTED EARNINGS ON COMMON STOCK					155,327,969	
56	ADJUSTED COMMON EQUITY AT YEAR-END					1,635,031,252	
57	ADJUSTED RETURN ON YEAR-END COMMON EQUITY					9.50%	
58							
59	**IF IDAHO RETURN ON COMMON EQUITY (Line 46) <9.5%**						
60	ADDITIONAL ITC ADJUSTMENT (Annualized) If L 54 is negative, then 0; if positive, then smaller of L54 or $25,000,000					0	
61							
62	**IF IDAHO RETURN ON COMMON EQUITY (Line 46) >10%**						
63	IDAHO EARNINGS GREATER THAN 10% ROE BUT LESS THAN 10.5%					9,259,492	(L50-L49)/(1-10%)
64							
65	**IF IDAHO RETURN ON COMMON EQUITY (Line 46) >10.5%**						
66	INCREMENTAL IDAHO EARNINGS GREATER THAN 10.50% ROE					13,408,731	(L43-L50)/(1-10.5%)
67							
68	**Per Order #32424:**					After Tax	Tax Gross Up
69	ROE between 10%-10.5% --CUSTOMER SHARE - 50% (Reduction to rates)					4,629,746	7,602,043
70	ROE between 10%-10.5% --COMPANY SHARE - 50%					4,629,746	
71	ROE greater than 10.5% (Incremental) -- CUSTOMER SHARE - 75% (Offset to Pension balance)					10,056,549	16,512,853
72	ROE greater than 10.5% (Incremental) --COMPANY SHARE - 25%					3,352,183	
73						22,668,223	
74							

Prepared by: Kelley Noe on 1-14-14

Reviewed by: _______________

Exhibit No. 3
Case No. IPC-E-14-05
T. Tatum, IPC
Page 1 of 1

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-14-05

IDAHO POWER COMPANY

TATUM, DI
TESTIMONY

EXHIBIT NO. 4

Idaho Power Company
Calculation of Revenue Impact
Class Allocated Revenue Sharing Benefits
State of Idaho
Filed April 15, 2014

Line No	Tariff Description	Rate Sch. No.	(A) Average Number of Customers	(B) Normalized Energy (kWh)	(C) Proposed NPSE Base Revenue	(D) Percentage of Idaho Base Revenues	(E) Allocated Revenue Sharing Benefit	(F) Cents per kWh Rate	(G) Percent Revenue Change
	Uniform Tariff Rates:								
1	Residential Service	1	412,772	4,905,224,592	$ 447,498,404	44.83%	$ (3,408,014)	(0.000695)	(0.76)%
2	Master Metered Mobile Home Park	3	23	4,983,593	431,464	0.04%	(3,286)	(0.000659)	(0.76)%
3	Residential Service Time-of-Day	5	1,483	26,868,737	2,340,544	0.23%	(17,825)	(0.000663)	(0.76)%
4	Small General Service	7	28,078	143,241,424	16,347,378	1.64%	(124,497)	(0.000869)	(0.76)%
5	Large General Service - Secondary	9S	33,046	3,164,200,200	215,224,132	21.56%	(1,639,083)	(0.000518)	(0.76)%
6	Large General Service - Primary	9P	203	462,178,285	27,355,829	2.74%	(208,334)	(0.000451)	(0.76)%
7	Large General Service - Transmission	9T	3	2,426,064	148,319	0.01%	(1,130)	(0.000466)	(0.76)%
8	Dusk to Dawn Lighting	15	0	6,399,685	1,274,790	0.13%	(9,708)	(0.001517)	(0.76)%
9	Large Power Service - Secondary	19S	1	6,349,085	373,236	0.04%	(2,842)	(0.000448)	(0.76)%
10	Large Power Service - Primary	19P	106	2,119,873,345	111,149,720	11.13%	(846,483)	(0.000399)	(0.76)%
11	Large Power Service - Transmission	19T	2	33,704,165	1,702,784	0.17%	(12,968)	(0.000385)	(0.76)%
12	Agricultural Irrigation Service	24	17,415	1,752,403,245	129,471,992	12.97%	(986,020)	(0.000563)	(0.76)%
13	Unmetered General Service	40	1,296	12,162,729	990,677	0.10%	(7,545)	(0.000620)	(0.76)%
14	Street Lighting	41	1,344	26,964,987	3,438,456	0.34%	(26,186)	(0.000971)	(0.76)%
15	Traffic Control Lighting	42	454	2,826,554	$162,894	0.02%	-$1,241	(0.000439)	(0.76)%
16	Total Uniform Tariffs		496,226	12,669,806,690	$ 957,910,618	95.96%	$ (7,295,161)		(0.76)%
17	Special Contracts								
18	Micron	26	1	466,006,690	$ 21,500,609	2.15%	$ (163,742)	NA	(0.76)%
19	J R Simplot	29	1	186,125,488	8,192,346	0.82%	(62,390)	NA	(0.76)%
20	DOE	30	1	236,926,098	10,603,060	1.06%	(80,750)	NA	(0.76)%
21	Total Special Contracts		3	889,058,276	$ 40,296,014	4.04%	$ (306,882)		(0.76)%
22	Total Idaho Retail Sales		496,229	13,558,864,966	$ 998,206,633	100.00%	$ (7,602,043)		(0.76)%

Note:
June 1, 2014 - May 31, 2015, Forecast