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March 25, 2016

VIA ELECTRONIC MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

Re: UE 301 – In the Matter of IDAHO POWER COMPANY's 2016 Annual Power Cost Update

Attention Filing Center:

Attached for filing in the above-referenced matter is an electronic copy of Idaho Power Company's March Forecast - Testimony of Kelley K. Noe.

Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Attachment

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 301

IN THE MATTER OF IDAHO POWER COMPANY'S 2016 ANNUAL POWER COST UPDATE	)
MARCH FORECAST	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

KELLEY K. NOE

March 25, 2016

Q. Are you the same Kelley K. Noe who previously submitted testimony in this proceeding?

A. Yes. I previously submitted direct and reply testimony in this proceeding regarding the October Update for the 2016 Annual Power Cost Update ("APCU"). The 2016 October Update is Idaho Power Company's ("Company") estimate of what "normalized" power supply expenses will be for the upcoming APCU test period of April 2016 through March 2017.

Q. What is the status of the October Update in this proceeding?

A. The Company filed the 2016 October Update on October 23, 2015, and Staff of the Public Utility Commission of Oregon ("Commission") and the Citizens' Utility Board of Oregon ("CUB") reviewed the filing. Several rounds of discovery requests have been served on the Company since the initial filing. On January 20, 2016, a settlement conference was held with all parties to the case. No settlement was reached at the conclusion of the settlement conference. On February 12, 2016, Staff filed opening testimony and CUB indicated that they would not be filing opening testimony. On March 18, 2016, the Company filed reply testimony in response to issues raised in Staff's opening testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the second part of the Company's APCU filing, which is the March Forecast as detailed in Order No. 08-238. If approved, the 2016 APCU (both the October Update and March Forecast components) will result in a revenue increase of approximately $0.4 million, or 0.71 percent, to become effective June 1, 2016.

Q. How is your testimony organized?

A. My testimony begins by describing the differences between the October Update and the March Forecast and the filing requirements associated with it. Next, my testimony describes the required updates to the AURORAxmp Electric Market Model ("AURORA"). I then present and discuss the forecast of total net power supply expenses ("NPSE") for the 2016 March Forecast and how they compare to last year's 2015 March Forecast. My testimony concludes with the quantification of the projected revenue deficiency and the proposed rate implementation to eliminate that deficiency.

Q. Have you prepared exhibits for this proceeding?

A. Yes, I am sponsoring the following exhibits:

1. Exhibit 301, Forward Price Curves used for re-pricing purchased power and surplus sales
2. Exhibit 302, determination of expected NPSE for the 2016 March Forecast
3. Exhibit 303, October Update and March Forecast combined rate calculation
4. Exhibit 304, Revenue Spread
5. Exhibit 305, Calculation of Revenue Impact

March Forecast Overview

Q. What is the March Forecast?

A. The March Forecast is the Company's quantification of the "expected" NPSE for the APCU test period of April through March, as determined by the AURORA model.

Q. How does the March Forecast differ from the October Update?

A. The October Update was calculated by simulating 87 water year conditions in the AURORA model and then averaging the results of all 87 resulting NPSE scenarios to create an "average" or "normal" expectation of NPSE. In contrast, the March Forecast is calculated by simulating the "expected" water condition during the upcoming APCU test period based on the most recent water supply forecast and current reservoir levels from the Northwest River Forecast Center ("NRFC"). The results for the October Update are used to update base rates, while the results for the March Forecast are used to update Schedule 55, Annual Power Cost Update.

AURORA Model Inputs

Q. Please describe the variables that are to be updated in the AURORA model for the March Forecast as described in Order No. 08-238.

A. The following variables are described in Order No. 08-238 to be updated in the March Forecast:

a. Fuel prices and transportation costs;

b. Wheeling expenses;

c. Planned outages and forced outage rates;

d. Heat rates;

e. Forecast of normalized sales and loads, updated only for known significant changes since the October APCU filing;

f. Forecast hydro generation from stream flow conditions using the most recent water supply forecast from the NRFC and current reservoir levels;

g. Contracts for wholesale power and power purchases and sales;

h. Forward price curve as defined below;

i. Public Utility Regulatory Policies Act of 1978 ("PURPA") contract expenses; and

j. The Oregon state allocation factor.

Q. How do the modeling variables, as described in Order No. 08-238, compare between the 2016 March Forecast and those used to develop the 2016 October Update?

A. All of the modeling variables described in Order No. 08-238 were reviewed for accuracy, and updated where appropriate, in the preparation of the proposed March Forecast. For the April 2016 through March 2017 test period, the following variables changed since the October APCU determination was prepared: (1) fuel prices, (2) planned outage schedule, (3) forced outage rates, (4) normalized sales and loads, (5) forecast of hydro generation and current reservoir levels from stream flow conditions using the most recent water supply forecast from the NRFC, (6) known power purchases and surplus sales made in compliance with the Company's Energy Risk Management Policy, (7) forward price curve, and (8) PURPA contract expenses.

Fuel Expense

Q. How frequently are the Company's fuel cost forecasts updated?

A. The coal and gas price forecasts are refreshed monthly for operational planning purposes. When the October Update was prepared, information from the September 2015 Operations Plan was used. The March Forecast determination of NPSE includes the Company's most current coal and gas price forecasts.

Q. How did the AURORA modeled dispatch cost of coal generation change compared to the October Update results?

A. The modeled dispatch per-unit cost for each of the Company's coal-fired thermal generation plants has been updated to reflect current operating costs. The modeled dispatch per-unit cost at the Jim Bridger power plant ("Bridger") increased from \$27.44 per megawatt-hour ("MWh") to \$28.06 per MWh. The per-unit cost of output at the Boardman plant remained virtually unchanged, moving from \$25.32 per MWh to \$25.33 per MWh. The per-unit cost of output at the Valmy plant ("Valmy") increased from \$32.39 per MWh to \$36.00 per MWh.

Q. Were the Oil, Handling, and Administrative and General ("OHAG") expenses modeled in the same manner as the October Update?

A. Yes. OHAG expenses were removed from the AURORA modeled dispatch cost and included as a fixed-cost input in the APCU, consistent with the October Update.

Q. What factors drove the changes in the AURORA modeled dispatch cost of generation at the Company's coal plants since the October Update was filed?

A. While the coal costs, on a $ per MMBtu basis, at each of the Company's coal-fired plants remained relatively constant between the October Update and the March Forecast, the increase in the per-unit cost of generation for Bridger and Valmy can be attributed to higher operating costs spread over lower production volumes. The lower production volumes are primarily due to the continued decrease in natural gas prices. Lower natural gas prices impact the production volumes at the coal-fired plants in two ways: (1) it shifts the dispatch of coal-fired generating units to natural gas generating units; and (2) it reduces wholesale electric market prices. The lower market prices reduce the ability to economically dispatch the Company's coal-fired plants for surplus sales.

Q. How did the gas price forecast included in the March Forecast change as compared to the gas price forecast included in the October Update?

A. The gas price forecast used for the October Update for Henry Hub was $3.06 per MMBtu, while the gas price forecast used for the March Forecast for Henry Hub was $2.68 per MMBtu, a decrease of $0.38 per MMBtu. The decrease in the Henry Hub price from the October Update to the March Forecast was driven by lower demand and higher gas supply nationally. My understanding is that lower demand was primarily the result of reduced demand in the residential and commercial sectors, while the gas supply increased due to milder temperatures which resulted in fewer natural gas wellhead freeze-offs over the winter. In addition, from a regional perspective, water equivalent in the form of snow pack has developed better year-to-date than anticipated due to the El Niño weather pattern. This fundamental regional market driver has put downward pressure on Mid-Columbia ("Mid-C") wholesale power curves, and thus forced Sumas market prices lower as well.

Q. How is the Henry Hub gas price forecast used as an AURORA input?

A. The Company uses the gas price forecast for Henry Hub as the starting point in the AURORA model. Henry Hub is considered a reference fuel in AURORA, meaning other gas market prices are determined by applying an adjustment factor to the Henry Hub price. For example, a Henry Hub gas price of $2.68 per MMBtu applied to a Sumas basis of a negative $0.29 per MMBtu equals a Sumas gas price of $2.39 per MMBtu ($2.68 + ($0.29) = $2.39). The Company develops a separate gas price for its natural gas units also based upon the Henry Hub gas price forecast.

PURPA Expense

Q. Please describe any changes to PURPA generation since the October Update.

A. The October Update included 361 average megawatts ("aMW") of available PURPA generation, whereas the PURPA generation included in the March Forecast is 358 aMW, a decrease of 3 aMW since the October Update. There was no change to the number of PURPA contracts between the October Update and the March Forecast; however, the forecast of PURPA generation was updated based on the latest generation data.

Q. How does total PURPA expense included in the March Forecast compare to the level of PURPA expense included in the October Update?

A. Total PURPA expense included in the March Forecast is $209.2 million compared to the $208.9 million included in the October Update, an increase of $0.3 million. The PURPA forecast prepared for the March Forecast included updated contract values which drove the increase in expense even though there was a slight decrease in total generation compared to the forecast prepared for the October Update.

Normalized Load

Q. Please explain the magnitude of change between the forecast of normalized load used in the October Update and the March Forecast.

A. The forecast of normalized load used for the October Update was expected to be 1,815 aMW. The forecast of normalized load used for the March Forecast is expected to be 1,811 aMW, a decrease of 4 aMW. The decrease of 4 aMW is due to the revised load forecast from one of the Company's large industrial customers that occurred between the October and March filings.

Hydro Forecast

Q. What was the date of the water supply forecast from the NRFC that was used to create the hydro generation forecast for the March Forecast?

A. The forecast of monthly hydro generation levels included in the March Forecast reflects the NRFC's March 7, 2016, forecast. The March 7, 2016, Forecast has expected inflows into Brownlee Reservoir for April through July of 4.62 million acre-feet ("MAF"), or 84 percent of the (1981-2010) average level of 5.47 MAF.

Q. How does this year's water supply forecast compare to last year's NRFC's forecast?

A. The NRFC's forecast used in last year's March Forecast was 3.74 MAF compared to this year's forecast of 4.62 MAF, which is 24 percent higher than last year, yet still below the 30-year average by 0.85 MAF.

Q. Please explain why the higher NRFC forecast of inflows at Brownlee does not translate into a proportional increase in hydro generation compared to last year.

A. The hydro generation forecasted for this year's March Forecast is 7.8 million MWh compared to 7.6 million MWh in last year's March Forecast. While the hydro output did increase year-over-year, the increase was not more substantial because of decreased flows coming from the upper Snake Basin. The reservoir levels in the upper Snake Basin are lower than they were in 2015 which has resulted in no projected flood control from the upper Snake Basin as there was in 2015. This would indicate that most of the difference between the 2015 forecast of 3.74 MAF and the 2016 4.62 MAF is additional flow from the Payette and Boise Basins. In other words, while there will be additional generation from Brownlee and through the Hells Canyon Complex, there will not be additional generation at all of the upstream generation facilities from American Falls to Swan Falls.

Q. What significance does a lower than average stream flow forecast have on the Company's variable power supply expenses?

A. Because a significant portion of the Company's generation fleet is hydro-based, a lower than average stream flow forecast has a detrimental effect on the Company's variable power supply expenses. The hydro generation forecasted under the normalized scenario for the October Update was 8.7 million MWh, while the hydro generation forecasted under this year's March Forecast is 7.8 million MWh, a decrease of 0.87 million MWh or 99 aMW (0.87 million MWh ÷ 8,760 hours = 99 aMW).

Known Power Purchases and Surplus Sales

Q. Did the Company include known power purchases and surplus sales resulting from the Company's Energy Risk Management Policy in the March Forecast?

A. Yes. The Company includes known power purchases and surplus sales resulting from the Company's Energy Risk Management Policy and incorporates those amounts as Net Hedges on Exhibit No. 302, lines 29 and 30, as directed by Order No. 08-238. Known power purchases and surplus sales are not included in the October Update of the APCU.

Other

Q. What other AURORA inputs have changed since the October Update?

A. The Company updated the maintenance rates and forced outage rates for its thermal plants. Heat rates remain unchanged from the October Update.

2016 Forecast NPSE

Q. Have you prepared an exhibit that summarizes the total NPSE for the March Forecast?

A. Yes. Exhibit No. 302 shows the results of the AURORA modeling determination of forecast NPSE, as well as the re-pricing of market purchases and surplus sales, and total PURPA expense for the April 2016 through March 2017 test year.

Re-Pricing Based on a Forward Price Curve

Q. What forward price curve did the Company use to price purchased power and surplus sales?

A. Exhibit No. 301 shows the March 9, 2016, Mid-C Heavy-load (HL) and Light Load (LL) forward price curve for the April 2016 through March 2017 test period the Company used for the March Forecast, as directed by Order No. 08-238.

Q. What is the Company's March Forecast of NPSE as a result of the changes described above?

A. Exhibit No. 302 shows the results of a single water condition for the April 2016 through March 2017 test period, with updated fuel prices, normalized load, updated stream flow conditions, updated power purchases and surplus sales from the Company's Energy Risk Management Policy (Net Hedges), market purchased power and surplus sales re-priced, and updated PURPA contract expenses. The March Forecast for NPSE without PURPA expenses is $164.1 million. When PURPA expenses of $209.2 million are included, the total NPSE for the March Forecast is $373.4 million.

Per-Unit Cost Calculation

Q. What is the March Forecast unit cost per MWh as determined by the Company for this filing?

A. Exhibit No. 302 shows the normalized annual sales at the customer level for the April 2016 through March 2017 test period of 14,604,270 MWh, line 34. Based upon test period sales, the cost per-unit for the March Forecast to become effective on June 1, 2016, is $25.56 per MWh ($373.4 million / 14.604 million MWh = $25.56 per MWh), lines 33, 34, and 36.

Q. How does this $25.56 per MWh March Forecast compare to the March Forecast that resulted from last year's computation?

A. The March Forecast for last year's April 2015 through March 2016 test period was $25.00 per MWh, as compared to this year's April 2016 through March 2017 test period of $25.56 per MWh, an increase of $0.56 per MWh.

Quantification and Discussion of the Revenue Deficiency

Q. Please describe the calculation necessary to determine the March Forecast Rate Adjustment.

A. Exhibit No. 303 steps through the Commission-specified method of calculating the March Forecast rate, pursuant to Order No. 08-238. Lines 1-3 show the calculation for the October Update rate of $24.08 per MWh. Lines 4-6 show the calculation for the March Forecast rate of $25.56 per MWh. Line 7 is calculated by the March Forecast rate minus the October Update rate multiplied by the March Forecast of Normalized Sales (line 6 minus line 3 multiplied by line 4). Line 8 is the allocated amount (95 percent) that is allowed for the March Forecast rate. Line 9, the Forecast Change Allowed, is calculated by multiplying line 7 by line 8. Line 10 is calculated by dividing line 9 by line 4 to calculate the March Forecast rate adjustment of $1.41 per MWh.

Q. How is the incremental revenue requirement for the March Forecast calculated using the March Forecast rate adjustment unit cost of $1.41 per MWh?

A. The incremental revenue requirement or "revenue deficiency" for the March Forecast is calculated by multiplying the unit cost of $1.41 per MWh by the loss adjusted Oregon jurisdictional sales for the April 2016 through March 2017 test period of 688,412.209 MWh, creating a revenue deficiency of nearly $1.0 million, as shown on page 2 of Exhibit 304, lines 47, 48, and 49.

Q. How does the modeled generation in the 2016 March Forecast compare to last year's March Forecast?

A. A high level analysis of the results suggests that lower priced natural gas generation combined with additional PURPA generation have replaced more coal generation and allowed for higher surplus sales volume when compared to last year's March Forecast levels.

Q. If less expensive natural gas-fired generation is replacing coal generation and surplus sales volume increased, why is NPSE increasing as compared to last year's March Forecast?

A. The forecasted natural gas prices discussed earlier in my testimony result in an average per-unit cost of $16.86 per MWh at the Langley Gulch plant, whereas the modeled dispatch per-unit cost at the Company's coal plants varies from $25.33 to $36.00 per MWh. If all of the coal generation was replaced with only cheaper natural gas generation, total NPSE would have been lower. However, the coal generation was also offset by additional PURPA generation, a must take resource regardless of its per-unit cost, which in this instance is $67 per MWh.

Surplus sales volumes were 0.7 million MWh higher than last year's March Forecast; however, the re-pricing based on the March 9, 2016, forward price curve reduced the value of surplus sales from $20.28 per MWh (as modeled in AURORA) to $13.78 per MWh, which resulted in an increase of $7.5 million in the surplus sales component of NPSE.

Q. Can you elaborate more on the changes in generation from the 2015 March Forecast to the 2016 March Forecast?

A. The hydro generation forecasted for the 2016 March Forecast was 0.2 million MWh more than last year. The increased hydro generation is due to higher forecasted inflows at Brownlee reservoir.

Lower natural gas prices increased production at all of the Company's natural gas-fired plants by 0.5 million MWh compared to last year's March Forecast. The cost of production from last year's March Forecast for all natural gas-fired generation was $25.56 per MWh, while this year's March Forecast expects an average price of $21.42 per MWh, a reduction of $4.14 per MWh.

Market purchase volumes have decreased from nearly 1.0 million MWh to 0.6 million MWh, a decrease of nearly 0.4 million MWh from last year's March Forecast. The average re-priced market purchase price from last year's March Forecast was $27.76 per MWh, while this year's March Forecast expects an average market purchase price of $20.23 per MWh, a decrease of $7.53 per MWh, resulting in a $2.5 million decrease to NPSE.

Coal generation decreased 0.5 million MWh compared to last year's forecast due to the increase in lower priced natural gas generation and PURPA which reduced the level of coal generation that could be economically dispatched.

Rate Implementation

Q. What method of allocation are you proposing to spread the incremental revenue requirement associated with the March Forecast to the various customer classes?

A. I am proposing to allocate the revenue deficiency associated with the 2016 March Forecast according to the revenue spread methodology approved by the Commission in UE 214, Order No. 10-191. Order No. 10-191 established a revenue-spread methodology whereby the revenue deficiency for the March Forecast is allocated to individual customer classes on the basis of the total generation-related revenue requirement approved in the Company's last general rate case. In this instance, the Company's last general rate case, UE 233, was a settled case in which the parties did not adopt the Company's class cost-of-service methodology, but rather agreed to a revenue spread methodology that was set forth in Exhibit B to the Partial Stipulation filed on February 1, 2012. In light of the stipulated revenue spread, the Company has utilized the total generation-related revenue requirement detailed on Exhibit B to the Partial Stipulation to apportion the March Forecast revenue requirement to each customer class. The proposed revenue spread resulting from the application of the stipulated methodology in UE 233 is shown on Exhibit No. 304.

Q. Did the Company revise the revenue spread for the October Update?

A. Yes. The Company revised the revenue spread for the October update to align with the loss adjusted sales that were used for the March Forecast filing. The practice of updating the revenue spread for the October Update is consistent with the method applied in the last four APCU filings in UE 242, UE 257, UE 279, and UE 293. The loss adjusted sales for the October Update were 647,119.324 MWh, whereas the loss adjusted sales for the March Forecast are 688,412.209, an increase of 41,292.89 MWh. The change in loss adjusted sales increases the October Update revenue requirement from $414,156 to $440,584, an increase of $26,428. Exhibit No. 304 also contains the revised October Update revenue spread.

Q. What is the overall revenue impact of this year's combined October Update and March Forecast compared to last year's combined October Update and March Forecast using the rate spread methodology described above?

A. Exhibit No. 305 provides a summary of the revenue change resulting from this year's combined October Update and March Forecast as compared to current revenue. As can be seen on line 12 of Exhibit No. 305, the overall revenue impact of this year's combined October Update and March Forecast is an increase of approximately $0.4 million or .71 percent overall. The $0.4 million increase reflects the $1.4 million associated with the 2016 APCU (October Update and March Forecast) compared to what is currently included in Oregon customers' rates related to the 2015 APCU.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 301
MARCH FORECAST

Exhibit Accompanying Testimony of Kelley K. Noe

March 9, 2016, Mid-Columbia Price Curve for April 2016 – March 2017

March 25, 2016

IDAHO POWER COMPANY
Mid-Columbia Heavy Load and Light Load Daily Forward Curves
Used to Re-Price Purchased Power (PP) and Surplus Sales (SS) for the March Forecast

Line	Mid-Columbia Forward Price Curve on:												
1	**3/9/2016**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**
2	**mc HL**	11.55	10.55	12.55	18.7	23.4	21.85	20.85	23.05	27.2	25.55	25.1	21.3
3	**mc LL**	7.65	5.15	6.4	11.4	17.85	17.95	18.45	19.75	23.15	21.75	22.35	18.9
4	**Reallocated Prices**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**
5	**HL PP**												
6	103.9%	12.00	10.96	13.04	19.43	24.31	22.70	21.66	23.95	28.26	26.55	26.08	22.13
7	**LL PP**												
8	107.1%	8.19	5.52	6.85	12.21	19.12	19.22	19.76	21.15	24.79	23.29	23.94	20.24
9	**HL SS**												
10	96.4%	11.13	10.17	12.10	18.03	22.56	21.06	20.10	22.22	26.22	24.63	24.20	20.53
11	**LL SS**												
12	93.4%	7.15	4.81	5.98	10.65	16.67	16.77	17.23	18.45	21.62	20.31	20.87	17.65

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 301
MARCH FORECAST

Exhibit Accompanying Testimony of Kelley K. Noe

Power Supply Costs for April 1, 2016 – March 31, 2017

March 25, 2016

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2016 -- MARCH 31, 2017 (One Hydro Condition)
Repriced Using UE 195 Settlement Methodology - March Forecast

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	789,849.7	921,629.2	790,396.5	607,454.9	437,657.4	518,002.2	485,114.5	373,046.7	450,667.6	700,611.3	835,710.3	885,537.4	7,795,677.9
	Bridger													
2	Energy (MWh)	-	-	10,569.9	277,993.2	296,167.0	89,470.2	102,049.9	226,484.7	330,459.7	195,193.9	55,680.6	23,420.7	1,607,489.7
	Expense ($ x 1000)	-	-	304.8	7,769.1	8,264.6	2,614.9	2,889.0	6,346.5	9,076.1	5,510.6	1,630.8	694.5	45,100.9
	O&M Expense ($ x 1000)	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	3,538.4
3	Total Expense ($ x 1000)	$ 294.9	$ 294.9	$ 599.7	$ 8,063.9	$ 8,559.5	$ 2,909.7	$ 3,183.9	$ 6,641.4	$ 9,371.0	$ 5,805.5	$ 1,925.7	$ 989.4	$ 48,639.3
	Boardman													
4	Energy (MWh)	824.4	2,473.2	10,560.4	31,644.5	40,004.5	23,889.6	21,637.6	27,933.0	39,796.0	23,994.3	8,565.7	8,640.7	239,963.8
	Expense ($ x 1000)	25.0	74.9	274.9	772.9	972.6	595.0	546.6	689.0	964.5	650.8	251.5	261.4	6,079.0
	O&M Expense ($ x 1000)	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	356.4
5	Total Expense ($ x 1000)	$ 54.7	$ 104.6	$ 304.6	$ 802.6	$ 1,002.3	$ 624.7	$ 576.3	$ 718.7	$ 994.2	$ 680.5	$ 281.2	$ 291.1	$ 6,435.4
	Valmy													
6	Energy (MWh)	-	-	-	3,795.9	4,710.3	-	-	3,980.1	13,166.2	-	-	-	25,652.4
	Expense ($ x 1000)	-	-	-	139.9	165.9	-	-	144.9	472.8	-	-	-	923.5
	O&M Expense ($ x 1000)	340.4	340.4	340.4	340.4	340.4	340.4	340.4	340.4	340.4	340.4	340.4	340.4	4,085.0
7	Total Expense ($ x 1000)	$ 340.4	$ 340.4	$ 340.4	$ 480.3	$ 506.3	$ 340.4	$ 340.4	$ 485.3	$ 813.2	$ 340.4	$ 340.4	$ 340.4	$ 5,008.5
	Langley Gulch													
8	Energy (MWh)	182,044.0	192,593.5	192,118.3	198,265.8	198,717.1	192,354.0	193,779.4	176,336.0	193,411.3	180,107.7	121,318.4	145,177.2	2,166,222.8
9	Expense ($ x 1000)	$ 2,268.0	$ 2,162.0	$ 2,236.6	$ 2,731.2	$ 2,833.9	$ 2,766.4	$ 3,172.3	$ 3,664.7	$ 4,706.1	$ 4,163.3	$ 2,697.2	$ 3,122.9	$ 36,524.6
	Danskin													
10	Energy (MWh)	15,005.5	41,282.9	85,760.9	103,437.6	110,624.1	72,713.5	12,072.6	451.4	4.8	-	-	31.1	441,384.4
11	Expense ($ x 1000)	$ 314.0	$ 784.0	$ 1,717.2	$ 2,416.4	$ 2,663.1	$ 1,743.0	$ 326.7	$ 15.3	$ 0.2	$ -	$ -	$ 1.1	$ 9,980.9
	Bennett Mountain													
12	Energy (MWh)	2,312.9	5,180.0	48,862.5	79,680.8	81,779.4	48,142.9	1,646.5	79.2	-	-	-	-	267,684.1
13	Expense ($ x 1000)	$ 49.3	$ 100.3	$ 980.8	$ 1,871.2	$ 1,983.1	$ 1,174.0	$ 45.3	$ 2.7	$ -	$ -	$ -	$ -	$ 6,206.8
14	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 723.2	$ 746.8	$ 732.2	$ 765.4	$ 765.4	$ 741.2	$ 746.8	$ 723.2	$ 746.8	$ 748.8	$ 677.7	$ 748.8	$ 8,866.1
	Purchased Power (Excluding CSPP)													
15	Market Energy (MWh)	8,734.6	1,877.4	63,783.6	28,476.8	103,628.0	62,370.2	41,817.6	105,546.3	78,677.1	84,649.5	13,889.0	5,879.5	599,329.6
16	Elkhorn Wind Energy (MWh)	25,790.0	24,592.0	23,934.6	26,559.8	24,064.4	19,958.8	20,960.4	30,426.8	29,073.2	24,269.2	24,158.8	28,532.8	302,320.5
17	Neal Hot Springs Energy (MWh)	14,424.2	10,940.5	11,065.3	7,822.4	9,924.6	11,286.0	12,896.6	16,671.7	17,970.0	18,765.7	16,385.0	16,782.0	164,934.1
18	Raft River Geothermal Energy (MWh)	6,213.3	5,111.2	5,097.5	5,661.1	5,734.4	5,757.2	7,594.7	6,634.5	6,897.6	6,890.5	6,324.0	6,504.2	74,420.3
19	Total Energy Excl. CSPP (MWh)	55,162.1	42,521.1	103,880.9	68,520.1	143,351.5	99,372.1	83,269.3	159,279.3	132,617.8	134,574.9	60,756.8	57,698.5	1,141,004.5
20	Market Expense ($ x 1000)	$ 72.3	$ 12.0	$ 575.1	$ 388.2	$ 2,123.2	$ 1,277.2	$ 855.9	$ 2,354.0	$ 1,997.6	$ 2,012.6	$ 336.4	$ 119.2	$ 12,123.8
21	Elkhorn Wind Expense ($ x 1000)	$ 1,115.4	$ 1,063.6	$ 1,408.5	$ 1,875.4	$ 1,699.2	$ 1,174.6	$ 1,233.5	$ 2,148.4	$ 2,052.9	$ 1,471.0	$ 1,464.3	$ 1,271.1	$ 17,977.9
22	Neal Hot Springs Expense ($ x 1000)	$ 1,155.2	$ 876.2	$ 1,209.1	$ 1,025.7	$ 1,301.3	$ 1,233.2	$ 1,409.2	$ 2,186.0	$ 2,356.2	$ 2,098.6	$ 1,832.3	$ 1,375.6	$ 18,058.7
23	Raft River Geothermal Expense ($ x 1000)	$ 289.1	$ 237.8	$ 322.7	$ 430.0	$ 435.6	$ 364.4	$ 480.7	$ 504.0	$ 523.9	$ 445.3	$ 408.7	$ 309.0	$ 4,751.3
24	Total Expense Excl. CSPP ($ x 1000)	$ 2,632.1	$ 2,189.7	$ 3,515.4	$ 3,719.2	$ 5,559.3	$ 4,049.4	$ 3,979.4	$ 7,192.4	$ 6,930.6	$ 6,027.5	$ 4,041.8	$ 3,074.9	$ 52,911.7
	Surplus Sales													
25	Energy (MWh)	263,012.9	255,235.0	84,523.0	95,035.6	32,517.4	16,202.6	36,614.2	6,259.2	27,397.9	25,645.0	115,419.3	188,669.2	1,146,531.2
26	Revenue Including Transmission Costs ($ x 1000)	$ 2,674.6	$ 2,165.5	$ 861.4	$ 1,603.0	$ 719.9	$ 315.9	$ 689.2	$ 127.4	$ 711.0	$ 616.1	$ 2,712.2	$ 3,746.5	$ 16,942.8
27	Transmission Costs ($ x 1000)	$ 263.0	$ 255.2	$ 84.5	$ 95.0	$ 32.5	$ 16.2	$ 36.6	$ 6.3	$ 27.4	$ 25.6	$ 115.4	$ 188.7	$ 1,146.5
28	Revenue Excluding Transmission Costs ($ x 1000)	$ 2,411.6	$ 1,910.3	$ 776.9	$ 1,507.9	$ 687.4	$ 299.7	$ 652.5	$ 121.2	$ 683.6	$ 590.5	$ 2,596.8	$ 3,557.9	$ 15,796.3
	Net Hedges													
29	Energy (MWh)	-	-	-	159,200.0	32,400.0	-	-	-	-	-	-	-	191,600.0
30	Cost($ X 1000)	$ -	$ -	$ -	$ 4,229.8	$ 1,134.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,363.8
31	Net Power Supply Expenses ($ x 1000)	$ 4,264.9	$ 4,812.3	$ 9,650.1	$ 23,572.1	$ 24,319.5	$ 14,049.0	$ 11,718.6	$ 19,322.4	$ 22,878.4	$ 17,175.6	$ 7,367.2	$ 5,010.6	**$ 164,140.8**
32	PURPA ($ x 1000)	$17,176.58	$19,451.45	$21,602.23	$22,935.21	$21,132.72	$18,179.57	$16,191.63	$16,100.42	$15,794.73	$12,316.84	$14,576.81	$13,754.93	$ 209,213.1
33	Total Net Power Supply Expenses ($ x 1000)	$ 21,441.4	$ 24,263.8	$ 31,252.3	$ 46,507.3	$ 45,452.2	$ 32,228.6	$ 27,910.2	$ 35,422.9	$ 38,673.1	$ 29,492.4	$ 21,944.0	$ 18,765.5	**$ 373,353.9**
34	Sales at Customer Level (In 000s MWH)	1,027.006	1,048.528	1,229.108	1,472.664	1,552.659	1,385.664	1,109.193	1,031.240	1,152.209	1,277.132	1,213.385	1,105.482	14,604.270
35	Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
36	Unit Cost / MWH (for PCAM)	$20.88	$23.14	$25.43	$31.58	$29.27	$23.26	$25.16	$34.35	$33.56	$23.09	$18.08	$16.97	**$25.56**
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
37	Portion of Purchased Power considered HL	**2.27%**	16.19%	34.96%	19.69%	26.40%	36.02%	37.19%	41.16%	17.19%	14.82%	13.40%	1.45%	
38	Purchased Power HL Price	12.00	10.96	13.04	19.43	24.31	22.70	21.66	23.95	28.26	26.55	26.08	22.13	
39	Portion of Surplus Sales considered HL Sur	**75.81%**	68.55%	68.85%	84.28%	92.91%	63.56%	55.45%	50.71%	94.15%	85.98%	78.99%	76.55%	
40	Surplus Sales HL Price	11.13	10.17	12.10	18.03	22.56	21.06	20.10	22.22	26.22	24.63	24.20	20.53	
	Light Load													
41	Portion of Purchased Power considered LL	**97.73%**	83.81%	65.04%	80.31%	73.60%	63.98%	62.81%	58.84%	82.81%	85.18%	86.60%	98.55%	
42	Purchased Power LL Price	8.19	5.52	6.85	12.21	19.12	19.22	19.76	21.15	24.79	23.29	23.94	20.24	
43	Portion of Surplus Sales considered LL Sur	**24.19%**	31.45%	31.15%	15.72%	7.09%	36.44%	44.55%	49.29%	5.85%	14.02%	21.01%	23.45%	
44	Surplus Sales LL Price	7.15	4.81	5.98	10.65	16.67	16.77	17.23	18.45	21.62	20.31	20.87	17.65	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 301
MARCH FORECAST

Exhibit Accompanying Testimony of Kelley K. Noe

Annual Power Cost Update for April 2016 – March 2017

March 25, 2016

ANNUAL POWER COST UPDATE
April 2016 - March 2017

Line		
	OCTOBER APCU	
1	Forecast of Normalized Sales (MWh)	14,616,871
2	Total Net Power Supply Expense	$352,028,075
3	October APCU Rate ($/MWh)	$24.08
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	14,604,270
5	Total Net Power Supply Expense	$373,353,887
6	March Forecast Rate ($/MWh)	$25.56
7	Sales Adjusted Forecast Power Cost Change	$21,614,320
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$20,533,604
10	**March Forecast Rate Adjustment ($/MWh)**	$1.41
11	**Combined Rate ($/MWh)**	$25.49

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 301
MARCH FORECAST

Exhibit Accompanying Testimony of Kelley K. Noe

Revenue Spread for October Update and March Forecast

March 25, 2016

Idaho Power Company

Rate Spread Exhibit for October Update APCU -- O&M Outside AURORA

General Rate Case (UE 233): Marginal Cost-of-Service Study and Stipulated Revenue Spread

2011 Test Period

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) GEN SRV TRANS (9-T)	(G) AREA LIGHTING (15)	(H) LG POWER PRIMARY (19-P)	(I) LG POWER TRANS (19-T)	(J) IRRIGATION SECONDARY (24-S)	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)
1	**Normalized Sales (kWh)**	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
2	**Current Revenue**	$39,873,591	$15,355,932	$1,559,400	$6,975,915	$798,102	$154,997	$112,462	$8,213,065	$3,123,393	$3,454,271	$972	$123,851	$1,231
3														
4	**Demand Related Marginal Cost**													
5	Generation - Staff Adj.	$11,049,450	$4,082,443	$268,043	$1,671,178	$207,813	$35,425	$625	$1,790,415	$1,483,718	$1,508,400	$158	$1,035	$200
6	Transmission - Staff Adj.	$12,432,118	$4,593,297	$301,584	$1,880,300	$233,817	$39,858	$703	$2,014,458	$1,669,382	$1,697,153	$177	$1,165	$225
7	Distribution	$6,945,625	$3,215,110	$181,233	$1,319,947	$100,783	$0	$5,738	$798,946	$0	$1,314,267	$161	$9,350	$89
8														
9	**Energy Related Marginal Cost**													
10	Generation	$28,547,004	$8,940,577	$802,452	$5,140,232	$649,911	$117,743	$21,383	$7,662,010	$3,097,424	$2,079,568	$570	$34,414	$722
11	Transmission - Staff Adj.	$4,144,040	$1,297,863	$116,488	$746,184	$94,345	$17,092	$3,104	$1,112,259	$449,639	$301,881	$83	$4,996	$105
12														
13	**Simple-Summed Energy-Related and Demand-Related Marginal Costs**													
14	Generation Marginal Costs - Staff Adj.	$39,596,454	$13,023,020	$1,070,495	$6,811,410	$857,724	$153,168	$22,008	$9,452,425	$4,581,142	$3,587,968	$728	$35,449	$922
15	Transmission Marginal Costs - Staff Adj.	$16,576,157	$5,891,160	$418,072	$2,626,484	$328,162	$56,950	$3,807	$3,126,717	$2,119,021	$1,999,034	$260	$6,160	$330
16														
17	**Customer Related Marginal Cost**	$2,805,903	$1,967,110	$385,570	$177,410	$6,719	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873
18														
19	**Total Functionalized Revenue Requirement**													
20	Generation - Staff Adj.	$25,202,690	$8,289,003	$681,357	$4,335,384	$545,931	$97,490	$14,008	$6,016,360	$2,915,844	$2,283,701	$463	$22,563	$587
21														
22	Transmission	$4,272,366	$1,518,397	$107,755	$676,954	$84,581	$14,678	$981	$805,885	$546,160	$515,234	$67	$1,588	$85
23														
24	Distribution													
25	Demand-Related	$8,930,530	$4,133,917	$233,025	$1,697,158	$129,585	$0	$7,378	$1,027,267	$0	$1,689,855	$207	$12,022	$114
26	Customer-Related													
27	Allocated	$2,859,472	$2,004,665	$392,931	$180,797	$6,847	$1,417	$0	$15,498	$2,583	$251,682	$232	$1,928	$890
28	Direct Assignment	$419,424	$188,447	$34,356	$12,375	$69	$14	$78,778	$83	$14	$21,953	$42	$83,209	$83
29														
30	**Total: Staff-Adjusted Allocation**	$41,684,482	$16,134,429	$1,449,425	$6,902,669	$767,013	$113,599	$101,145	$7,865,094	$3,464,601	$4,762,425	$1,011	$121,310	$1,759
31	**Revenue Deficiency - Staff Adj. Allocation**	$1,810,890	$778,497	($109,975)	($73,246)	($31,089)	($41,398)	($11,317)	($347,971)	$341,208	$1,308,154	$39	($2,541)	$528
32	**% Increase Required by Staff Adj. Alloc. Approach**	4.54%	5.07%	-7.05%	-1.05%	-3.90%	-26.71%	-10.06%	-4.24%	10.92%	37.87%	4.02%	-2.05%	42.91%
33	**$ Increase Recommended per Stipulation**	**$1,810,890**	**$862,348**	**$44,153**	**$197,517**	**$22,598**	**$0**	**$0**	**$232,545**	**$212,777**	**$235,318**	**$44**	**$3,507**	**$84**
34	**% Increase Recommended per Stipulation**	**4.54%**	**5.62%**	**2.83%**	**2.83%**	**2.83%**	**0.00%**	**0.00%**	**2.83%**	**6.81%**	**6.81%**	**4.56%**	**2.83%**	**6.81%**
35	**Average Rate Given Stipulation ($/kWh)**	**0.0641**	**0.0816**	**0.0899**	**0.0628**	**0.0544**	**0.0547**	**0.2324**	**0.0471**	**0.0450**	**0.0791**	**0.0788**	**0.1637**	**0.0805**
36	**Final Revenue Allocation**	$41,684,481	$16,218,280	$1,603,553	$7,173,432	$820,700	$154,997	$112,462	$8,445,610	$3,336,170	$3,689,589	$1,016	$127,358	$1,315
37														
38	**Spread Floors and Ceilings:**													
39	No increase for those warranting a decrease greater than 8%													
40	2.83% increase for those warranting a decrease less than 8%													
41	No increase greater than one-and-one-half times the average increase													
	2016 October Update APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures													
42	2016 October Update APCU Cost of Service (Allocator -- Line 14)	$440,584	$144,905	$11,911	$75,790	$9,544	$1,704	$245	$105,176	$50,974	$39,923	$8	$394	$10
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	1.06%	0.89%	0.74%	1.06%	1.16%	1.10%	0.22%	1.25%	1.53%	1.08%	0.80%	0.31%	0.78%
44	Loss-Adjusted 2011 Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
45	2016 October Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*{Line 42/Line 44})	0.678	0.729	0.668	0.663	0.632	0.602	0.506	0.587	0.687	0.856	0.628	0.507	0.628
46	**APCU Incremental Rate for 2016 October Update (Mills per kWh) (Line 45*{Column A:[Line 44/Line 47]})**	**0.640**	**0.760**	**0.640**	**0.632**	**0.500**	**0.675**	**0.553**	**0.645**	**0.479**	**0.597**	**1.454**	**0.428**	**0.488**
47	*Loss-Adjusted 2016-2017 Normalized Sales (kWh)*	688,412,209	190,548,481	18,605,426	119,961,908	19,082,992	2,526,070	443,024	163,113,247	106,358,304	66,823,696	5,568	922,474	21,019
48	Projected October Update APCU 2016-2017 Revenues (Line 46 * Line 47)	$440,584	$144,905	$11,911	$75,790	$9,544	$1,704	$245	$105,176	$50,974	$39,923	$8	$394	$10

Notes:

1 **2016 October Update APCU Revenues = $0.64/MWh x 688,412.209 MWhs = $ 440,584** (Line 52, Column A)

2 **$0.64 =$24.08 (2016 October Update) - $23.44 (2015 October APCU Rate)**

Idaho Power Company
Rate Spread Exhibit for March Forecast APCU

General Rate Case (UE 233): Marginal Cost-of-Service Study and Stipulated Revenue Spread

2011 Test Period

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) GEN SRV TRANS (9-T)	(G) AREA LIGHTING (15)	(H) LG POWER PRIMARY (19-P)	(I) LG POWER TRANS (19-T)	(J) IRRIGATION SECONDARY (24-S)	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)
1	**Normalized Sales (kWh)**	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
2	**Current Revenue**	$39,873,591	$15,355,932	$1,559,400	$6,975,915	$798,102	$154,997	$112,462	$8,213,065	$3,123,393	$3,454,271	$972	$123,851	$1,231
3														
4	**Demand Related Marginal Cost**													
5	Generation - Staff Adj.	$11,049,450	$4,082,443	$268,043	$1,671,178	$207,813	$35,425	$625	$1,790,415	$1,483,718	$1,508,400	$158	$1,035	$200
6	Transmission - Staff Adj.	$12,432,118	$4,593,297	$301,584	$1,880,300	$233,817	$39,858	$703	$2,014,458	$1,669,382	$1,697,153	$177	$1,165	$225
7	Distribution	$6,945,625	$3,215,110	$181,233	$1,319,947	$100,783	$0	$5,738	$798,946	$0	$1,314,267	$161	$9,350	$89
8														
9	**Energy Related Marginal Cost**													
10	Generation	$28,547,004	$8,940,577	$802,452	$5,140,232	$649,911	$117,743	$21,383	$7,662,010	$3,097,424	$2,079,568	$570	$34,414	$722
11	Transmission - Staff Adj.	$4,144,040	$1,297,863	$116,488	$746,184	$94,345	$17,092	$3,104	$1,112,259	$449,639	$301,881	$83	$4,996	$105
12														
13	**Simple-Summed Energy-Related and Demand-Related Marginal Costs**													
14	Generation Marginal Costs - Staff Adj.	$39,596,454	$13,023,020	$1,070,495	$6,811,410	$857,724	$153,168	$22,008	$9,452,425	$4,581,142	$3,587,968	$728	$35,449	$922
15	Transmission Marginal Costs - Staff Adj.	$16,576,157	$5,891,160	$418,072	$2,626,484	$328,162	$56,950	$3,807	$3,126,717	$2,119,021	$1,999,034	$260	$6,160	$330
16														
17	**Customer Related Marginal Cost**	$2,805,903	$1,967,110	$385,570	$177,410	$6,719	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873
18														
19	**Total Functionalized Revenue Requirement**													
20	Generation - Staff Adj.	$25,202,690	$8,289,003	$681,357	$4,335,384	$545,931	$97,490	$14,008	$6,016,360	$2,915,844	$2,283,701	$463	$22,563	$587
21														
22	Transmission	$4,272,366	$1,518,397	$107,755	$676,954	$84,581	$14,678	$981	$805,885	$546,160	$515,234	$67	$1,588	$85
23														
24	Distribution													
25	Demand-Related	$8,930,530	$4,133,917	$233,025	$1,697,158	$129,585	$0	$7,378	$1,027,267	$0	$1,689,855	$207	$12,022	$114
26	Customer-Related													
27	Allocated	$2,859,472	$2,004,665	$392,931	$180,797	$6,847	$1,417	$0	$15,498	$2,583	$251,682	$232	$1,928	$890
28	Direct Assignment	$419,424	$188,447	$34,356	$12,375	$69	$14	$78,778	$83	$14	$21,953	$42	$83,209	$83
29														
30	**Total: Staff-Adjusted Allocation**	$41,684,482	$16,134,429	$1,449,425	$6,902,669	$767,013	$113,599	$101,145	$7,865,094	$3,464,601	$4,762,425	$1,011	$121,310	$1,759
31	**Revenue Deficiency - Staff Adj. Allocation**	$1,810,890	$778,497	($109,975)	($73,246)	($31,089)	($41,398)	($11,317)	($347,971)	$341,208	$1,308,154	$39	($2,541)	$528
32	**% Increase Required by Staff Adj. Alloc. Approach**	4.54%	5.07%	-7.05%	-1.05%	-3.90%	-26.71%	-10.06%	-4.24%	10.92%	37.87%	4.02%	-2.05%	42.91%
33	**$ Increase Recommended per Stipulation**	**$1,810,890**	**$862,348**	**$44,153**	**$197,517**	**$22,598**	**$0**	**$0**	**$232,545**	**$212,777**	**$235,318**	**$44**	**$3,507**	**$84**
34	**% Increase Recommended per Stipulation**	**4.54%**	**5.62%**	**2.83%**	**2.83%**	**2.83%**	**0.00%**	**0.00%**	**2.83%**	**6.81%**	**6.81%**	**4.56%**	**2.83%**	**6.81%**
35	**Average Rate Given Stipulation ($/kWh)**	**0.0641**	**0.0816**	**0.0899**	**0.0628**	**0.0544**	**0.0547**	**0.2324**	**0.0471**	**0.0450**	**0.0791**	**0.0788**	**0.1637**	**0.0805**
36	**Final Revenue Allocation**	$41,684,481	$16,218,280	$1,603,553	$7,173,432	$820,700	$154,997	$112,462	$8,445,610	$3,336,170	$3,689,589	$1,016	$127,358	$1,315
37														
38	**Spread Floors and Ceilings:**													
39	No increase for those warranting a decrease greater than 8%													
40	2.83% increase for those warranting a decrease less than 8%													
41	No increase greater than one-and-one-half times the average increase													

2016 March Forecast APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures

Line	Description	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
42	2016 March Forecast APCU Cost of Service (Allocator -- Line 14)	$970,661	$319,244	$26,242	$166,974	$21,026	$3,755	$540	$231,715	$112,301	$87,955	$18	$869	$23
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	2.33%	1.97%	1.64%	2.33%	2.56%	2.42%	0.48%	2.74%	3.37%	2.38%	1.75%	0.68%	1.72%
44	Proposed Combined Revenue Spread (Line 36 + Line 42)	$42,655,142	$16,537,524	$1,629,795	$7,340,405	$841,726	$158,752	$113,002	$8,677,326	$3,448,471	$3,777,543	$1,034	$128,227	$1,337
45	Loss-Adjusted 2011 Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
46	2016 March Forecast Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 42/Line 45))	1.493	1.606	1.471	1.461	1.393	1.326	1.115	1.293	1.514	1.885	1.382	1.117	1.384
47	**APCU Incremental Rate for 2016 March Forecast (Mills per kWh) (Line 46*(Column A:[Line 45/Line 48]))**	**1.410**	**1.675**	**1.410**	**1.392**	**1.102**	**1.486**	**1.218**	**1.421**	**1.056**	**1.316**	**3.203**	**0.942**	**1.075**
48	*Loss-Adjusted 2016-2017 Normalized Sales (kWh)*	688,412,209	190,548,481	18,605,426	119,961,908	19,082,992	2,526,070	443,024	163,113,247	106,358,304	66,823,696	5,568	922,474	21,019
49	Projected March Forecast APCU 2016-2017 Revenues (Line 47 * Line 48)	$970,661	$319,244	$26,242	$166,974	$21,026	$3,755	$540	$231,715	$112,301	$87,955	$18	$869	$23

Notes:

1 **2016 March Forecast APCU Revenues = $1.41/MWh x 688,412.209 MWhs =** **$ 970,661** **(Line 49, Column A)**

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 301
MARCH FORECAST

Exhibit Accompanying Testimony of Kelley K. Noe

Summary of Revenue Impact

March 25, 2016

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2016

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Current Billed Revenue	Mills Per kWh	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Mills Per kWh	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:									
1	Residential Service	1	13,694	190,548,481	$18,948,137	99.44	$150,914	$19,099,051	100.23	0.80%
2	Small General Service	7	2,531	18,605,426	$1,969,491	105.86	$10,866	$1,980,356	106.44	0.55%
3	Large General Service	9	913	141,570,970	$10,924,451	77.17	$87,126	$11,011,577	77.78	0.80%
4	Dusk to Dawn Lighting	15	0	443,024	$110,409	249.22	$266	$110,675	249.82	0.24%
5	Large Power Service	19	6	269,471,551	$16,553,536	61.43	$129,668	$16,683,204	61.91	0.78%
6	Agricultural Irrigation Service	24	1,856	66,823,696	$6,546,289	97.96	$13,766	$6,560,054	98.17	0.21%
7	Unmetered General Service	40	2	5,568	$537	96.51	$12	$550	98.74	2.31%
8	Street Lighting	41	25	922,474	$145,239	157.45	$447	$145,686	157.93	0.31%
9	Traffic Control Lighting	42	8	21,019	$1,997	95.02	$10	$2,007	95.51	0.52%
10	Total Uniform Tariffs		19,035	688,412,209	$55,200,087	80.18	$393,076	$55,593,162	80.76	0.71%
12	Total Oregon Retail Sales		19,035	688,412,209	$55,200,087	80.18	$393,076	$55,593,162	80.76	0.71%

(1) Updated April 2016-March 2017 Test Year

IDAHO POWER COMPANY
Mid-Columbia Heavy Load and Light Load Daily Forward Curves
Used to Re-Price Purchased Power (PP) and Surplus Sales (SS) for the March Forecast

Line	Mid-Columbia Forward Price Curve on:												
1	**3/9/2016**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**
2	**mc HL**	11.55	10.55	12.55	18.7	23.4	21.85	20.85	23.05	27.2	25.55	25.1	21.3
3	**mc LL**	7.65	5.15	6.4	11.4	17.85	17.95	18.45	19.75	23.15	21.75	22.35	18.9
4	**Reallocated Prices**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**
5	**HL PP**												
6	103.9%	12.00	10.96	13.04	19.43	24.31	22.70	21.66	23.95	28.26	26.55	26.08	22.13
7	**LL PP**												
8	107.1%	8.19	5.52	6.85	12.21	19.12	19.22	19.76	21.15	24.79	23.29	23.94	20.24
9	**HL SS**												
10	96.4%	11.13	10.17	12.10	18.03	22.56	21.06	20.10	22.22	26.22	24.63	24.20	20.53
11	**LL SS**												
12	93.4%	7.15	4.81	5.98	10.65	16.67	16.77	17.23	18.45	21.62	20.31	20.87	17.65

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2016 -- MARCH 31, 2017 (One Hydro Condition)
Repriced Using UE 195 Settlement Methodology - March Forecast

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	789,849.7	921,629.2	790,396.5	607,454.9	437,657.4	518,002.2	485,114.5	373,046.7	450,667.6	700,611.3	835,710.3	885,537.4	7,795,677.9
	Bridger													
2	Energy (MWh)	-	-	10,569.9	277,993.2	296,167.0	89,470.2	102,049.9	226,484.7	330,459.7	195,193.9	55,680.6	23,420.7	1,607,489.7
	Expense ($ x 1000)	-	-	304.8	7,769.1	8,264.6	2,614.9	2,889.0	6,346.5	9,076.1	5,510.6	1,630.8	694.5	45,100.9
	O&M Expense ($ x 1000)	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	3,538.4
3	Total Expense ($ x 1000)	$ 294.9	$ 294.9	$ 599.7	$ 8,063.9	$ 8,559.5	$ 2,909.7	$ 3,183.9	$ 6,641.4	$ 9,371.0	$ 5,805.5	$ 1,925.7	$ 989.4	$ 48,639.3
	Boardman													
4	Energy (MWh)	824.4	2,473.2	10,560.4	31,644.5	40,004.5	23,889.6	21,637.6	27,933.0	39,796.0	23,994.3	8,565.7	8,640.7	239,963.8
	Expense ($ x 1000)	25.0	74.9	274.9	772.9	972.6	595.0	546.6	689.0	964.5	650.8	251.5	261.4	6,079.0
	O&M Expense ($ x 1000)	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	356.4
5	Total Expense ($ x 1000)	$ 54.7	$ 104.6	$ 304.6	$ 802.6	$ 1,002.3	$ 624.7	$ 576.3	$ 718.7	$ 994.2	$ 680.5	$ 281.2	$ 291.1	$ 6,435.4
	Valmy													
6	Energy (MWh)	-	-	-	3,795.9	4,710.3	-	-	3,980.1	13,166.2	-	-	-	25,652.4
	Expense ($ x 1000)	-	-	-	139.9	165.9	-	-	144.9	472.8	-	-	-	923.5
	O&M Expense ($ x 1000)	340.4	340.4	340.4	340.4	340.4	340.4	340.4	340.4	340.4	340.4	340.4	340.4	4,085.0
7	Total Expense ($ x 1000)	$ 340.4	$ 340.4	$ 340.4	$ 480.3	$ 506.3	$ 340.4	$ 340.4	$ 485.3	$ 813.2	$ 340.4	$ 340.4	$ 340.4	$ 5,008.5
	Langley Gulch													
8	Energy (MWh)	182,044.0	192,593.5	192,118.3	198,265.8	198,717.1	192,354.0	193,779.4	176,336.0	193,411.3	180,107.7	121,318.4	145,177.2	2,166,222.8
9	Expense ($ x 1000)	$ 2,268.0	$ 2,162.0	$ 2,236.6	$ 2,731.2	$ 2,833.9	$ 2,766.4	$ 3,172.3	$ 3,664.7	$ 4,706.1	$ 4,163.3	$ 2,697.2	$ 3,122.9	$ 36,524.6
	Danskin													
10	Energy (MWh)	15,005.5	41,282.9	85,760.9	103,437.6	110,624.1	72,713.5	12,072.6	451.4	4.8	-	-	31.1	441,384.4
11	Expense ($ x 1000)	$ 314.0	$ 784.0	$ 1,717.2	$ 2,416.4	$ 2,663.1	$ 1,743.0	$ 326.7	$ 15.3	$ 0.2	$ -	$ -	$ 1.1	$ 9,980.9
	Bennett Mountain													
12	Energy (MWh)	2,312.9	5,180.0	48,862.5	79,680.8	81,779.4	48,142.9	1,646.5	79.2	-	-	-	-	267,684.1
13	Expense ($ x 1000)	$ 49.3	$ 100.3	$ 980.8	$ 1,871.2	$ 1,983.1	$ 1,174.0	$ 45.3	$ 2.7	$ -	$ -	$ -	$ -	$ 6,206.8
14	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 723.2	$ 746.8	$ 732.2	$ 765.4	$ 765.4	$ 741.2	$ 746.8	$ 723.2	$ 746.8	$ 748.8	$ 677.7	$ 748.8	$ 8,866.1
	Purchased Power (Excluding CSPP)													
15	Market Energy (MWh)	8,734.6	1,877.4	63,783.6	28,476.8	103,628.0	62,370.2	41,817.6	105,546.3	78,677.1	84,649.5	13,889.0	5,879.5	599,329.6
16	Elkhorn Wind Energy (MWh)	25,790.0	24,592.0	23,934.6	26,559.8	24,064.4	19,958.8	20,960.4	30,426.8	29,073.2	24,269.2	24,158.8	28,532.8	302,320.5
17	Neal Hot Springs Energy (MWh)	14,424.2	10,940.5	11,065.3	7,822.4	9,924.6	11,286.0	12,896.6	16,671.7	17,970.0	18,765.7	16,385.0	16,782.0	164,934.1
18	Raft River Geothermal Energy (MWh)	6,213.3	5,111.2	5,097.5	5,661.1	5,734.4	5,757.2	7,594.7	6,634.5	6,897.6	6,890.5	6,324.0	6,504.2	74,420.3
19	Total Energy Excl. CSPP (MWh)	55,162.1	42,521.1	103,880.9	68,520.1	143,351.5	99,372.1	83,269.3	159,279.3	132,617.8	134,574.9	60,756.8	57,698.5	1,141,004.5
20	Market Expense ($ x 1000)	$ 72.3	$ 12.0	$ 575.1	$ 388.2	$ 2,123.2	$ 1,277.2	$ 855.9	$ 2,354.0	$ 1,997.6	$ 2,012.6	$ 336.4	$ 119.2	$ 12,123.8
21	Elkhorn Wind Expense ($ x 1000)	$ 1,115.4	$ 1,063.6	$ 1,408.5	$ 1,875.4	$ 1,699.2	$ 1,174.6	$ 1,233.5	$ 2,148.4	$ 2,052.9	$ 1,471.0	$ 1,464.3	$ 1,271.1	$ 17,977.9
22	Neal Hot Springs Expense ($ x 1000)	$ 1,155.2	$ 876.2	$ 1,209.1	$ 1,025.7	$ 1,301.3	$ 1,233.2	$ 1,409.2	$ 2,186.0	$ 2,356.2	$ 2,098.6	$ 1,832.3	$ 1,375.6	$ 18,058.7
23	Raft River Geothermal Expense ($ x 1000)	$ 289.1	$ 237.8	$ 322.7	$ 430.0	$ 435.6	$ 364.4	$ 480.7	$ 504.0	$ 523.9	$ 445.3	$ 408.7	$ 309.0	$ 4,751.3
24	Total Expense Excl. CSPP ($ x 1000)	$ 2,632.1	$ 2,189.7	$ 3,515.4	$ 3,719.2	$ 5,559.3	$ 4,049.4	$ 3,979.4	$ 7,192.4	$ 6,930.6	$ 6,027.5	$ 4,041.8	$ 3,074.9	$ 52,911.7
	Surplus Sales													
25	Energy (MWh)	263,012.9	255,235.0	84,523.0	95,035.6	32,517.4	16,202.6	36,614.2	6,259.2	27,397.9	25,645.0	115,419.3	188,669.2	1,146,531.2
26	Revenue Including Transmission Costs ($ x 1000)	$ 2,674.6	$ 2,165.5	$ 861.4	$ 1,603.0	$ 719.9	$ 315.9	$ 689.2	$ 127.4	$ 711.0	$ 616.1	$ 2,712.2	$ 3,746.5	$ 16,942.8
27	Transmission Costs ($ x 1000)	$ 263.0	$ 255.2	$ 84.5	$ 95.0	$ 32.5	$ 16.2	$ 36.6	$ 6.3	$ 27.4	$ 25.6	$ 115.4	$ 188.7	$ 1,146.5
28	Revenue Excluding Transmission Costs ($ x 1000)	$ 2,411.6	$ 1,910.3	$ 776.9	$ 1,507.9	$ 687.4	$ 299.7	$ 652.5	$ 121.2	$ 683.6	$ 590.5	$ 2,596.8	$ 3,557.9	$ 15,796.3
	Net Hedges													
29	Energy (MWh)	-	-	-	159,200.0	32,400.0	-	-	-	-	-	-	-	191,600.0
30	Cost($ X 1000)	$ -	$ -	$ -	$ 4,229.8	$ 1,134.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,363.8
31	Net Power Supply Expenses ($ x 1000)	$ 4,264.9	$ 4,812.3	$ 9,650.1	$ 23,572.1	$ 24,319.5	$ 14,049.0	$ 11,718.6	$ 19,322.4	$ 22,878.4	$ 17,175.6	$ 7,367.2	$ 5,010.6	**$ 164,140.8**
32	PURPA ($ x 1000)	$17,176.58	$19,451.45	$21,602.23	$22,935.21	$21,132.72	$18,179.57	$16,191.63	$16,100.42	$15,794.73	$12,316.84	$14,576.81	$13,754.93	$ 209,213.1
33	Total Net Power Supply Expenses ($ x 1000)	$ 21,441.4	$ 24,263.8	$ 31,252.3	$ 46,507.3	$ 45,452.2	$ 32,228.6	$ 27,910.2	$ 35,422.9	$ 38,673.1	$ 29,492.4	$ 21,944.0	$ 18,765.5	**$ 373,353.9**
34	Sales at Customer Level (In 000s MWH)	1,027.006	1,048.528	1,229.108	1,472.664	1,552.659	1,385.664	1,109.193	1,031.240	1,152.209	1,277.132	1,213.385	1,105.482	14,604.270
35	Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
36	Unit Cost / MWH (for PCAM)	$20.88	$23.14	$25.43	$31.58	$29.27	$23.26	$25.16	$34.35	$33.56	$23.09	$18.08	$16.97	**$25.56**
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
37	Portion of Purchased Power considered HL	**2.27%**	16.19%	34.96%	19.69%	26.40%	36.02%	37.19%	41.16%	17.19%	14.82%	13.40%	1.45%	
38	Purchased Power HL Price	12.00	10.96	13.04	19.43	24.31	22.70	21.66	23.95	28.26	26.55	26.08	22.13	
39	Portion of Surplus Sales considered HL Sui	**75.81%**	68.55%	68.85%	84.28%	92.91%	63.56%	55.45%	50.71%	94.15%	85.98%	78.99%	76.55%	
40	Surplus Sales HL Price	11.13	10.17	12.10	18.03	22.56	21.06	20.10	22.22	26.22	24.63	24.20	20.53	
	Light Load													
41	Portion of Purchased Power considered LL	**97.73%**	83.81%	65.04%	80.31%	73.60%	63.98%	62.81%	58.84%	82.81%	85.18%	86.60%	98.55%	
42	Purchased Power LL Price	8.19	5.52	6.85	12.21	19.12	19.22	19.76	21.15	24.79	23.29	23.94	20.24	
43	Portion of Surplus Sales considered LL Sur	**24.19%**	31.45%	31.15%	15.72%	7.09%	36.44%	44.55%	49.29%	5.85%	14.02%	21.01%	23.45%	
44	Surplus Sales LL Price	7.15	4.81	5.98	10.65	16.67	16.77	17.23	18.45	21.62	20.31	20.87	17.65	

ANNUAL POWER COST UPDATE
April 2016 - March 2017

Line		
	OCTOBER APCU	
1	Forecast of Normalized Sales (MWh)	14,616,871
2	Total Net Power Supply Expense	$352,028,075
3	October APCU Rate ($/MWh)	$24.08
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	14,604,270
5	Total Net Power Supply Expense	$373,353,887
6	March Forecast Rate ($/MWh)	$25.56
7	Sales Adjusted Forecast Power Cost Change	$21,614,320
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$20,533,604
10	**March Forecast Rate Adjustment ($/MWh)**	$1.41
11	**Combined Rate ($/MWh)**	$25.49

Idaho Power Company
Rate Spread Exhibit for October Update APCU -- O&M Outside AURORA

General Rate Case (UE 233): Marginal Cost-of-Service Study and Stipulated Revenue Spread
2011 Test Period

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) GEN SRV TRANS (9-T)	(G) AREA LIGHTING (15)	(H) LG POWER PRIMARY (19-P)	(I) LG POWER TRANS (19-T)	(J) IRRIGATION SECONDARY (24-S)	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)
1	**Normalized Sales (kWh)**	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
2	**Current Revenue**	$39,873,591	$15,355,932	$1,559,400	$6,975,915	$798,102	$154,997	$112,462	$8,213,065	$3,123,393	$3,454,271	$972	$123,851	$1,231
3														
4	**Demand Related Marginal Cost**													
5	Generation - Staff Adj.	$11,049,450	$4,082,443	$268,043	$1,671,178	$207,813	$35,425	$625	$1,790,415	$1,483,718	$1,508,400	$158	$1,035	$200
6	Transmission - Staff Adj.	$12,432,118	$4,593,297	$301,584	$1,880,300	$233,817	$39,858	$703	$2,014,458	$1,669,382	$1,697,153	$177	$1,165	$225
7	Distribution	$6,945,625	$3,215,110	$181,233	$1,319,947	$100,783	$0	$5,738	$798,946	$0	$1,314,267	$161	$9,350	$89
8														
9	**Energy Related Marginal Cost**													
10	Generation	$28,547,004	$8,940,577	$802,452	$5,140,232	$649,911	$117,743	$21,383	$7,662,010	$3,097,424	$2,079,568	$570	$34,414	$722
11	Transmission - Staff Adj.	$4,144,040	$1,297,863	$116,488	$746,184	$94,345	$17,092	$3,104	$1,112,259	$449,639	$301,881	$83	$4,996	$105
12														
13	**Simple-Summed Energy-Related and Demand-Related Marginal Costs**													
14	Generation Marginal Costs - Staff Adj.	$39,596,454	$13,023,020	$1,070,495	$6,811,410	$857,724	$153,168	$22,008	$9,452,425	$4,581,142	$3,587,968	$728	$35,449	$922
15	Transmission Marginal Costs - Staff Adj.	$16,576,157	$5,891,160	$418,072	$2,626,484	$328,162	$56,950	$3,807	$3,126,717	$2,119,021	$1,999,034	$260	$6,160	$330
16														
17	**Customer Related Marginal Cost**	$2,805,903	$1,967,110	$385,570	$177,410	$6,719	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873
18														
19	**Total Functionalized Revenue Requirement**													
20	Generation - Staff Adj.	$25,202,690	$8,289,003	$681,357	$4,335,384	$545,931	$97,490	$14,008	$6,016,360	$2,915,844	$2,283,701	$463	$22,563	$587
21														
22	Transmission	$4,272,366	$1,518,397	$107,755	$676,954	$84,581	$14,678	$981	$805,885	$546,160	$515,234	$67	$1,588	$85
23														
24	Distribution													
25	Demand-Related	$8,930,530	$4,133,917	$233,025	$1,697,158	$129,585	$0	$7,378	$1,027,267	$0	$1,689,855	$207	$12,022	$114
26	Customer-Related													
27	Allocated	$2,859,472	$2,004,665	$392,931	$180,797	$6,847	$1,417	$0	$15,498	$2,583	$251,682	$232	$1,928	$890
28	Direct Assignment	$419,424	$188,447	$34,356	$12,375	$69	$14	$78,778	$83	$14	$21,953	$42	$83,209	$83
29														
30	**Total: Staff-Adjusted Allocation**	$41,684,482	$16,134,429	$1,449,425	$6,902,669	$767,013	$113,599	$101,145	$7,865,094	$3,464,601	$4,762,425	$1,011	$121,310	$1,759
31	**Revenue Deficiency - Staff Adj. Allocation**	$1,810,890	$778,497	($109,975)	($73,246)	($31,089)	($41,398)	($11,317)	($347,971)	$341,208	$1,308,154	$39	($2,541)	$528
32	**% Increase Required by Staff Adj. Alloc. Approach**	4.54%	5.07%	-7.05%	-1.05%	-3.90%	-26.71%	-10.06%	-4.24%	10.92%	37.87%	4.02%	-2.05%	42.91%
33	**$ Increase Recommended per Stipulation**	**$1,810,890**	**$862,348**	**$44,153**	**$197,517**	**$22,598**	**$0**	**$0**	**$232,545**	**$212,777**	**$235,318**	**$44**	**$3,507**	**$84**
34	**% Increase Recommended per Stipulation**	**4.54%**	**5.62%**	**2.83%**	**2.83%**	**2.83%**	**0.00%**	**0.00%**	**2.83%**	**6.81%**	**6.81%**	**4.56%**	**2.83%**	**6.81%**
35	**Average Rate Given Stipulation ($/kWh)**	**0.0641**	**0.0816**	**0.0899**	**0.0628**	**0.0544**	**0.0547**	**0.2324**	**0.0471**	**0.0450**	**0.0791**	**0.0788**	**0.1637**	**0.0805**
36	**Final Revenue Allocation**	$41,684,481	$16,218,280	$1,603,553	$7,173,432	$820,700	$154,997	$112,462	$8,445,610	$3,336,170	$3,689,589	$1,016	$127,358	$1,315
37														
38	**Spread Floors and Ceilings:**													
39	No increase for those warranting a decrease greater than 8%													
40	2.83% increase for those warranting a decrease less than 8%													
41	No increase greater than one-and-one-half times the average increase													

2016 October Update APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures

Line	Description	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
42	2016 October Update APCU Cost of Service (Allocator -- Line 14)	$440,584	$144,905	$11,911	$75,790	$9,544	$1,704	$245	$105,176	$50,974	$39,923	$8	$394	$10
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	1.06%	0.89%	0.74%	1.06%	1.16%	1.10%	0.22%	1.25%	1.53%	1.08%	0.80%	0.31%	0.78%
44	Loss-Adjusted 2011 Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
45	2016 October Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*{Line 42/Line 44})	0.678	0.729	0.668	0.663	0.632	0.602	0.506	0.587	0.687	0.856	0.628	0.507	0.628
46	**APCU Incremental Rate for 2016 October Update (Mills per kWh) (Line 45*{Column A:[Line 44/Line 47]})**	**0.640**	**0.760**	**0.640**	**0.632**	**0.500**	**0.675**	**0.553**	**0.645**	**0.479**	**0.597**	**1.454**	**0.428**	**0.488**
47	*Loss-Adjusted 2016-2017 Normalized Sales (kWh)*	688,412,209	190,548,481	18,605,426	119,961,908	19,082,992	2,526,070	443,024	163,113,247	106,358,304	66,823,696	5,568	922,474	21,019
48	Projected October Update APCU 2016-2017 Revenues (Line 46 * Line 47)	$440,584	$144,905	$11,911	$75,790	$9,544	$1,704	$245	$105,176	$50,974	$39,923	$8	$394	$10

Notes:

1 **2016 October Update APCU Revenues = $0.64/MWh x 688,412.209 MWhs =** **$ 440,584** **(Line 52, Column A)**

2 **$0.64 =$24.08 (2016 October Update) - $23.44 (2015 October APCU Rate)**

Idaho Power Company
Rate Spread Exhibit for March Forecast APCU

General Rate Case (UE 233): Marginal Cost-of-Service Study and Stipulated Revenue Spread
2011 Test Period

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) GEN SRV TRANS (9-T)	(G) AREA LIGHTING (15)	(H) LG POWER PRIMARY (19-P)	(I) LG POWER TRANS (19-T)	(J) IRRIGATION SECONDARY (24-S)	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)
1	**Normalized Sales (kWh)**	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
2	**Current Revenue**	$39,873,591	$15,355,932	$1,559,400	$6,975,915	$798,102	$154,997	$112,462	$8,213,065	$3,123,393	$3,454,271	$972	$123,851	$1,231
3														
4	**Demand Related Marginal Cost**													
5	Generation - Staff Adj.	$11,049,450	$4,082,443	$268,043	$1,671,178	$207,813	$35,425	$625	$1,790,415	$1,483,718	$1,508,400	$158	$1,035	$200
6	Transmission - Staff Adj.	$12,432,118	$4,593,297	$301,584	$1,880,300	$233,817	$39,858	$703	$2,014,458	$1,669,382	$1,697,153	$177	$1,165	$225
7	Distribution	$6,945,625	$3,215,110	$181,233	$1,319,947	$100,783	$0	$5,738	$798,946	$0	$1,314,267	$161	$9,350	$89
8														
9	**Energy Related Marginal Cost**													
10	Generation	$28,547,004	$8,940,577	$802,452	$5,140,232	$649,911	$117,743	$21,383	$7,662,010	$3,097,424	$2,079,568	$570	$34,414	$722
11	Transmission - Staff Adj.	$4,144,040	$1,297,863	$116,488	$746,184	$94,345	$17,092	$3,104	$1,112,259	$449,639	$301,881	$83	$4,996	$105
12														
13	**Simple-Summed Energy-Related and Demand-Related Marginal Costs**													
14	Generation Marginal Costs - Staff Adj.	$39,596,454	$13,023,020	$1,070,495	$6,811,410	$857,724	$153,168	$22,008	$9,452,425	$4,581,142	$3,587,968	$728	$35,449	$922
15	Transmission Marginal Costs - Staff Adj.	$16,576,157	$5,891,160	$418,072	$2,626,484	$328,162	$56,950	$3,807	$3,126,717	$2,119,021	$1,999,034	$260	$6,160	$330
16														
17	**Customer Related Marginal Cost**	$2,805,903	$1,967,110	$385,570	$177,410	$6,719	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873
18														
19	**Total Functionalized Revenue Requirement**													
20	Generation - Staff Adj.	$25,202,690	$8,289,003	$681,357	$4,335,384	$545,931	$97,490	$14,008	$6,016,360	$2,915,844	$2,283,701	$463	$22,563	$587
21														
22	Transmission	$4,272,366	$1,518,397	$107,755	$676,954	$84,581	$14,678	$981	$805,885	$546,160	$515,234	$67	$1,588	$85
23														
24	Distribution													
25	Demand-Related	$8,930,530	$4,133,917	$233,025	$1,697,158	$129,585	$0	$7,378	$1,027,267	$0	$1,689,855	$207	$12,022	$114
26	Customer-Related													
27	Allocated	$2,859,472	$2,004,665	$392,931	$180,797	$6,847	$1,417	$0	$15,498	$2,583	$251,682	$232	$1,928	$890
28	Direct Assignment	$419,424	$188,447	$34,356	$12,375	$69	$14	$78,778	$83	$14	$21,953	$42	$83,209	$83
29														
30	**Total: Staff-Adjusted Allocation**	$41,684,482	$16,134,429	$1,449,425	$6,902,669	$767,013	$113,599	$101,145	$7,865,094	$3,464,601	$4,762,425	$1,011	$121,310	$1,759
31	**Revenue Deficiency - Staff Adj. Allocation**	$1,810,890	$778,497	($109,975)	($73,246)	($31,089)	($41,398)	($11,317)	($347,971)	$341,208	$1,308,154	$39	($2,541)	$528
32	**% Increase Required by Staff Adj. Alloc. Approach**	4.54%	5.07%	-7.05%	-1.05%	-3.90%	-26.71%	-10.06%	-4.24%	10.92%	37.87%	4.02%	-2.05%	42.91%
33	**$ Increase Recommended per Stipulation**	**$1,810,890**	**$862,348**	**$44,153**	**$197,517**	**$22,598**	**$0**	**$0**	**$232,545**	**$212,777**	**$235,318**	**$44**	**$3,507**	**$84**
34	**% Increase Recommended per Stipulation**	**4.54%**	**5.62%**	**2.83%**	**2.83%**	**2.83%**	**0.00%**	**0.00%**	**2.83%**	**6.81%**	**6.81%**	**4.56%**	**2.83%**	**6.81%**
35	**Average Rate Given Stipulation ($/kWh)**	**0.0641**	**0.0816**	**0.0899**	**0.0628**	**0.0544**	**0.0547**	**0.2324**	**0.0471**	**0.0450**	**0.0791**	**0.0788**	**0.1637**	**0.0805**
36	**Final Revenue Allocation**	$41,684,481	$16,218,280	$1,603,553	$7,173,432	$820,700	$154,997	$112,462	$8,445,610	$3,336,170	$3,689,589	$1,016	$127,358	$1,315
37														
38	**Spread Floors and Ceilings:**													
39	No increase for those warranting a decrease greater than 8%													
40	2.83% increase for those warranting a decrease less than 8%													
41	No increase greater than one-and-one-half times the average increase													

2016 March Forecast APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures

Line	Description	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
42	2016 March Forecast APCU Cost of Service (Allocator -- Line 14)	$970,661	$319,244	$26,242	$166,974	$21,026	$3,755	$540	$231,715	$112,301	$87,955	$18	$869	$23
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	2.33%	1.97%	1.64%	2.33%	2.56%	2.42%	0.48%	2.74%	3.37%	2.38%	1.75%	0.68%	1.72%
44	Proposed Combined Revenue Spread (Line 36 + Line 42)	$42,655,142	$16,537,524	$1,629,795	$7,340,405	$841,726	$158,752	$113,002	$8,677,326	$3,448,471	$3,777,543	$1,034	$128,227	$1,337
45	Loss-Adjusted 2011 Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
46	2016 March Forecast Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 42/Line 45))	1.493	1.606	1.471	1.461	1.393	1.326	1.115	1.293	1.514	1.885	1.382	1.117	1.384
47	**APCU Incremental Rate for 2016 March Forecast (Mills per kWh) (Line 46*(Column A:[Line 45/Line 48]))**	**1.410**	**1.675**	**1.410**	**1.392**	**1.102**	**1.486**	**1.218**	**1.421**	**1.056**	**1.316**	**3.203**	**0.942**	**1.075**
48	*Loss-Adjusted 2016-2017 Normalized Sales (kWh)*	688,412,209	190,548,481	18,605,426	119,961,908	19,082,992	2,526,070	443,024	163,113,247	106,358,304	66,823,696	5,568	922,474	21,019
49	Projected March Forecast APCU 2016-2017 Revenues (Line 47 * Line 48)	$970,661	$319,244	$26,242	$166,974	$21,026	$3,755	$540	$231,715	$112,301	$87,955	$18	$869	$23

Notes:

1 **2016 March Forecast APCU Revenues = $1.41/MWh x 688,412.209 MWhs = $ 970,661 (Line 49, Column A)**

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2016

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Current Billed Revenue	Mills Per kWh	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Mills Per kWh	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:									
1	Residential Service	1	13,694	190,548,481	$18,948,137	99.44	$150,914	$19,099,051	100.23	0.80%
2	Small General Service	7	2,531	18,605,426	$1,969,491	105.86	$10,866	$1,980,356	106.44	0.55%
3	Large General Service	9	913	141,570,970	$10,924,451	77.17	$87,126	$11,011,577	77.78	0.80%
4	Dusk to Dawn Lighting	15	0	443,024	$110,409	249.22	$266	$110,675	249.82	0.24%
5	Large Power Service	19	6	269,471,551	$16,553,536	61.43	$129,668	$16,683,204	61.91	0.78%
6	Agricultural Irrigation Service	24	1,856	66,823,696	$6,546,289	97.96	$13,766	$6,560,054	98.17	0.21%
7	Unmetered General Service	40	2	5,568	$537	96.51	$12	$550	98.74	2.31%
8	Street Lighting	41	25	922,474	$145,239	157.45	$447	$145,686	157.93	0.31%
9	Traffic Control Lighting	42	8	21,019	$1,997	95.02	$10	$2,007	95.51	0.52%
10	Total Uniform Tariffs		19,035	688,412,209	$55,200,087	80.18	$393,076	$55,593,162	80.76	0.71%
12	Total Oregon Retail Sales		19,035	688,412,209	$55,200,087	80.18	$393,076	$55,593,162	80.76	0.71%

(1) Updated April 2016-March 2017 Test Year