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March 20, 2015

VIA ELECTRONIC

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

Re: UE 293 In The Matter of IDAHO POWER COMPANY's 2015 Annual Power Cost Update – March Forecast

Attention Filing Center:

Attached for filing in the above-captioned docket is Idaho Power Company's Direct Testimony of Scott Wright.

Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 293

IN THE MATTER OF IDAHO POWER COMPANY'S 2015 ANNUAL POWER COST UPDATE	)))
MARCH FORECAST	))))

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

SCOTT WRIGHT

March 20, 2015

Q. Are you the same Scott Wright who previously submitted testimony in this proceeding?

A. Yes. I previously submitted testimony in this proceeding regarding the October Update for the 2015 Annual Power Cost Update ("APCU"). The 2015 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 2015 through March 2016.

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

A. The Company filed the 2015 October Update on October 21, 2014, and Staff of the Public Utility Commission of Oregon ("Commission") and the Citizens' Utility Board of Oregon reviewed the filing. Several rounds of discovery requests were served on the Company after the initial filing. On January 22, 2015, a settlement conference was held with all parties to the case. At the conclusion of the settlement conference, no party had any issues with the per-unit cost of $23.44 per megawatt-hour ("MWh") proposed by the Company for the 2015 October Update. Based on the parties' positions, the Commission Staff notified the Commission on January 28, 2015, that all parties to the case have agreed to amend the case schedule to remove all events prior to the filing of the March Forecast, which was subsequently approved January 29, 2015.

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.

Q. What is the March Forecast?

A. The March Forecast is the Company's estimate of the "expected" net power supply expense ("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 is calculated by simulating 86 water year conditions in the AURORA model and then averaging the results of all 86 NPSE 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.

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. After reviewing all of the inputs used for the October Update, which of the above variables were updated for the March Forecast?

A. All of the above variables were reviewed for the March Forecast; however, for the April 2015 through March 2016 test period only the following variables have changed since the October APCU determination was prepared: (1) fuel prices, (2) heat rates, (3) forecast of hydro generation and current reservoir levels from stream flow conditions using the most recent water supply forecast from the NRFC, (4) known power purchases and surplus sales made in compliance with the Company's Energy Risk Management Policy, (5) forward price curve, and (6) PURPA contract expenses.

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 October 2014 Operations Plan was used. The March Forecast determination of NPSE includes the Company's most current coal and gas price forecasts.

Q. What impact does the current coal price forecast have on the per-unit cost of output when compared to the October Update results?

A. The modeled per-unit cost of generation from AURORA, in terms of dollars per MWh increased at the Jim Bridger power plant ("Bridger") from $26.25 per MWh to $29.53 per MWh, decreased at the Boardman power plant ("Boardman") from $27.57 per MWh to $25.89 per MWh and increased at the Valmy power plant ("Valmy") from $35.45 per MWh to $37.05 per MWh. The generation cost modeled by AURORA includes both variable and fixed fuel components, as well as the inclusion of any start-up costs.

Q. What factors drove the changes in the per-unit cost of generation at the Company's coal plants since the October Update was filed?

A. The increase in the per-unit cost of generation for the Bridger plant is attributed to a combination of factors: (1) higher operating costs at the Bridger mine and (2) lower production volumes at the Bridger plant. As mentioned in the October Update, roof support measures to further enhance the safety of Bridger Coal Company miners, and changes in underground mine plans due to coal seam variability, weak geological formations overlying the coal seam, and previously unrecognized faults all continue to contribute additional mine costs. Further, as wholesale electric market prices have continued to drop between the October Update and the March Forecast, the ability to economically dispatch Bridger for surplus sales has been reduced. Therefore, operating costs are being spread across fewer units of production resulting in higher per-unit generation costs at Bridger.

The decrease in the per-unit cost of generation for the Boardman plant can be attributed to changes in contract prices. When the October Update was filed, it was anticipated that a new contract for additional coal was needed. When the March Forecast was prepared, the additional coal was removed from the forecast, which eliminated the higher price contract that was anticipated for the October Update, therefore, reducing the per-unit cost of generation for the Boardman plant.

The increase in the per-unit cost of generation at the Valmy plant can be attributed to multiple start-ups, which have a negative impact on the plant's heat rate. By comparison, the October Update analysis resulted in the dispatch of Valmy for 12 months out of the year and averaged 14 start-ups over the 12-month time period. Lower market energy prices in the March Forecast reduced the frequency that the Valmy plant could be economically dispatched. As a result, Valmy was dispatched for two months out of the year and averaged nine start-ups over the two-month time period. While the coal costs for Valmy remained relatively constant between the October Update and the March Forecast, the per-unit cost of generation suffered due to the changes in heat rates caused by the multiple start-ups and shut-downs over a relatively short period of time.

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 $4.07 per MMBtu, while the gas price forecast used for the March Forecast for Henry Hub was $3.21 per MMBtu, a decrease of $0.86 per MMBtu. The decrease in the Henry Hub price from the October Update to the March Forecast is driven by higher than expected gas supply resulting from: (1) supply outpacing demand on a daily basis and (2) the forecast that was derived for the October Update anticipated a harsher winter that never materialized. Forecasted gas storage levels for the October Update anticipated storage levels slightly below the five-year average for that time period, while gas storage levels for this year's March Forecast anticipate gas storage levels to be even with the five-year average for this time of year, therefore, ensuring adequate storage levels.

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 reference Henry Hub and apply an adjustment factor in order to develop a basis for the respective prices. For example, a Henry Hub gas price of $3.21 per MMBtu applied to a Sumas basis of ($0.04) per MMBtu equals a Sumas gas price of $3.17 per MMBtu ($3.21 + ($0.04) = $3.17). The Company develops a separate gas price for its natural gas units also based upon the Henry Hub gas price forecast.

Q. What prompted a heat rate adjustment between the October Update and March Forecast?

A. The Company uses a 12-month ending heat rate for modeling purposes. Because there was a six-month gap between the October Update and March Forecast, the 12-month ending heat rate was refreshed to reflect the latest six months. In this case, the Bridger plant experienced some minor improvements in its heat rate, while Boardman and Valmy experienced small declines in their respective heat rates.

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 6, 2015, forecast ("March 6th Forecast"). The March 6th Forecast has expected inflows into Brownlee Reservoir for April through July of 3.74 million acre-feet ("MAF"), or 68 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 3.86 MAF compared to this year's forecast of 3.74 MAF, which is 3 percent lower than last year, and still below the 30-year average by 1.73 MAF. However, as I will describe in greater detail later in my testimony, this year's March Forecast of hydro generation exceeds last year's modeled hydro generation.

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 7.6 million MWh, a decrease of 0.9 million MWh or 102 average megawatt.

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 Risk Energy Management Policy and incorporates those amounts as Net Hedges on Exhibit No. 202, lines 29 and 30, as directed by Order No. 08-238.

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

A. Exhibit No. 201 shows the March 10, 2015, Mid-Columbia forward price curve for the April 2015 through March 2016 test period the Company used, as directed by Order No. 08-238.

Q. Did the Company update its PURPA contract expenses for the March Forecast?

A. Yes. Since the October Update was filed, two additional PURPA contracts are now expected to be operational during the April 2015 through March 2016 test period.

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

A. The total PURPA expense included in the March Forecast is $174.9 million compared to the $172.8 million included in the October Update, an increase of $2.1 million.

Q. What is the Company's March Forecast of net power supply expense as a result of the changes described above?

A. Exhibit No. 202 shows the results of a single water condition for the April 2015 through March 2016 test period, with updated heat rates, fuel prices, updated stream flow conditions and reservoir levels, updated power purchases and surplus sales from the Company's Energy Risk Management Policy (Net Hedges), market purchased power and surplus sales repriced, and updated PURPA contract expenses. The March Forecast for NPSE without PURPA expenses is $187.2 million. When PURPA expenses of $174.9 million are included, the total NPSE for the March Forecast is $362.1 million.

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

A. Exhibit No. 202 shows the normalized annual sales at the customer level for the April 2015 through March 2016 test period are 14,484,458 MWh, line 34. Based upon test period sales, the cost per-unit for the March Forecast to become effective on June 1, 2015, is $25.00 per MWh ($362.1 million / 14.484 million MWh = $25.00 per MWh), lines 33, 34, and 36.

Q. How does this $25.00 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 2014 through March 2015 test period was $26.23 per MWh, as compared to this year's April 2015 through March 2016 test period of $25.00 per MWh, a decrease of $1.23 per MWh.

Q. What contributed to this year's March Forecast being a reduction from last year's March Forecast?

A. The main factors contributing to a reduction in this year's March Forecast as compared to last year's March Forecast are additional hydro generation, lower natural gas prices, and lower electric market prices, which are all described in more detail below.

The hydro generation forecasted for last year's March Forecast was 7.1 million MWh, whereas the hydro generation forecasted for this year's March Forecast is 7.6 million MWh, an increase of 0.5 million MWh. The increased generation is due to higher reservoir levels at Brownlee reservoir and higher forecasted Mid-Snake River flows over last year's forecast. Even though this year's NRFC inflow forecast was 3 percent less than last year's March Forecast, the additional water available due to higher reservoir levels and increased flows at the Mid-Snake projects produce slightly higher generation levels over last year's March Forecast.

Lower natural gas prices increased production at the Langley Gulch power plant ("Langley Gulch"), from 0.9 million MWh in last year's March Forecast to 2.1 million MWh for this year's March Forecast, an increase of 1.2 million MWh. The average cost of production from last year's March Forecast for Langley Gulch was $31.60 per MWh, while this year's March Forecast expects an average Langley Gulch price of $20.70 per MWh, a reduction of $10.90 per MWh.

Market purchase volumes have increased from 0.6 million MWh to nearly 1.0 million MWh, an increase of nearly 0.4 million MWh. The average market purchase price from last year's March Forecast was $37.03 per MWh, while this year's March Forecast expects an average market purchase price of $28.62 per MWh, a decrease of $8.42 per MWh.

With the increase in hydro generation, gas generation, and lower market purchase prices, lower cost generation and market purchases are displacing previously dispatched coal generation. In addition to these factors, lower forecasted electric market prices have reduced the level of coal generation that can be economically dispatched for surplus sales. This is evident with the 1.3 million MWh reduction between last year's March Forecast and this year's March Forecast. The average surplus sales price from last year's March Forecast was $27.97 per MWh, while this year's March Forecast expects an average surplus sales price of $22.44 per MWh, a reduction of $5.53 per MWh.

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

A. Exhibit No. 203 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 $23.44 per MWh. Lines 4-6 show the calculation for the March Forecast Rate of $25.00 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 create the March Forecast Rate Adjustment of $1.48 per MWh.

Q. How is the incremental revenue requirement for the March Forecast calculated using the March Forecast Rate Adjustment unit cost of $1.48 per MWh?

A. The incremental revenue requirement or "revenue deficiency" for the March Forecast is calculated by multiplying the unit cost of $1.48 per MWh by the loss adjusted Oregon jurisdictional sales for the April 2015 through March 2016 test period of 640,595.652 MWh, creating a revenue deficiency of nearly $1.0 million.

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 2015 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 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. 204.

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 three APCU filings in UE 242, UE 257, and UE 279. The loss adjusted sales for the October Update were 653,468.079 MWh, whereas the loss adjusted sales for the March Forecast is 640,595.652, a reduction of 12,872.427 MWh. The change in loss adjusted sales decreases the October Update revenue requirement from $1,058,618 to $1,037,765, a decrease of $20,853. Exhibit No. 204 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. 205 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. 205, the overall revenue impact of this year's combined October Update and March Forecast is a decrease of approximately $0.7

million or 1.36 percent overall. The $0.7 million decrease reflects the $2 million associated with the 2015 APCU (October Update and March Forecast) less the $2.7 million currently included in Oregon customers' rates related to the 2014 APCU.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 293
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

March 10, 2015, Mid-Columbia Price Curve for April 2015 – March 2016

March 20, 2015

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	**3/10/2015**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**
2	**mc HL**	25.10	24.95	25.90	31.90	33.65	29.30	25.95	27.70	31.25	29.55	27.85	24.30
3	**mc LL**	20.25	18.30	19.30	23.95	25.95	23.55	21.95	23.95	26.50	24.75	23.90	20.80
4	**Reallocated Prices**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**
5	**HL PP**												
6	103.9%	26.08	25.92	26.91	33.14	34.96	30.44	26.96	28.78	32.47	30.70	28.94	25.25
7	**LL PP**												
8	107.1%	21.69	19.60	20.67	25.65	27.79	25.22	23.51	25.65	28.38	26.51	25.60	22.28
9	**HL SS**												
10	96.4%	24.20	24.05	24.97	30.75	32.44	28.25	25.02	26.70	30.13	28.49	26.85	23.43
11	**LL SS**												
12	93.4%	18.91	17.09	18.03	22.37	24.24	22.00	20.50	22.37	24.75	23.12	22.32	19.43

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 293
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

Power Supply Costs for April 1, 2015 – March 31, 2016

March 20, 2015

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2015 – MARCH 31, 2016 (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)	692,364.6	898,710.5	635,505.0	614,553.0	476,113.4	472,334.0	511,207.8	408,394.7	620,427.9	703,527.0	874,627.3	724,608.7	7,632,373.9
	Bridger													
2	Energy (MWh)	-	10,961.8	184,872.8	375,266.1	369,544.4	208,454.5	163,686.0	198,862.6	272,576.7	136,632.0	22,847.0	61,360.0	2,005,063.9
3	Expense ($ x 1000)	$ -	$ 349.5	$ 5,461.6	$ 10,873.3	$ 10,720.7	$ 6,093.5	$ 4,879.2	$ 5,926.7	$ 8,050.3	$ 4,191.6	$ 727.2	$ 1,932.6	$ 59,206.1
	Boardman													
4	Energy (MWh)	3,093.7	-	18,898.9	37,647.1	37,223.6	29,781.4	25,008.6	27,144.2	40,955.0	27,387.1	15,621.5	19,694.3	282,455.3
5	Expense ($ x 1000)	$ 92.6	$ -	$ 488.5	$ 951.9	$ 938.4	$ 765.8	$ 649.3	$ 696.0	$ 1,025.1	$ 736.5	$ 435.3	$ 532.2	$ 7,311.7
	Valmy													
6	Energy (MWh)	-	-	-	39,248.5	-	-	-	-	12,469.7	-	-	-	51,718.2
7	Expense ($ x 1000)	$ -	$ -	$ -	$ 1,434.9	$ -	$ -	$ -	$ -	$ 481.3	$ -	$ -	$ -	$ 1,916.2
	Langley Gulch													
8	Energy (MWh)	139,895.6	146,544.6	181,092.9	198,499.8	198,559.8	191,285.3	191,148.6	174,220.9	195,399.9	181,849.0	149,510.5	176,659.0	2,124,665.8
9	Expense ($ x 1000)	$ 2,557.1	$ 2,612.3	$ 3,202.1	$ 3,598.5	$ 3,704.5	$ 3,591.3	$ 3,763.0	$ 3,983.7	$ 4,894.9	$ 4,489.3	$ 3,565.1	$ 4,017.3	$ 43,979.0
	Danskin													
10	Energy (MWh)	217.2	11.3	16,152.1	66,220.3	53,253.2	31,807.3	4,200.3	142.2	310.2	109.7	46.6	-	172,470.2
11	Expense ($ x 1000)	$ 6.5	$ 0.3	$ 469.7	$ 2,001.0	$ 1,646.5	$ 979.3	$ 135.2	$ 5.3	$ 12.5	$ 4.4	$ 1.8	$ -	$ 5,262.4
	Bennett Mountain													
12	Energy (MWh)	-	-	2,331.8	44,385.1	27,246.4	6,281.6	432.1	-	-	-	-	-	80,676.9
13	Expense ($ x 1000)	$ -	$ -	$ 69.0	$ 1,346.0	$ 849.0	$ 196.5	$ 14.1	$ -	$ -	$ -	$ -	$ -	$ 2,474.6
14	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 737.6	$ 761.7	$ 746.6	$ 780.3	$ 780.3	$ 755.6	$ 761.7	$ 737.6	$ 761.7	$ 761.7	$ 713.6	$ 761.7	$ 9,059.8
	Purchased Power (Excluding CSPP)													
15	Market Energy (MWh)	37,218.4	14,138.1	135,154.1	138,973.0	161,040.4	103,418.6	43,901.2	104,271.2	71,621.3	103,519.4	12,981.1	34,892.6	961,129.5
16	Elkhorn Wind Energy (MWh)	23,518.2	24,014.7	23,574.3	26,612.0	26,462.2	20,831.4	22,703.6	23,844.0	25,274.9	27,546.2	23,761.2	27,261.8	296,404.6
17	Neal Hot Springs Energy (MWh)	13,569.7	10,684.5	11,067.6	7,824.1	8,991.1	9,658.6	11,060.4	14,749.6	19,041.5	18,746.8	16,677.7	16,242.3	158,313.9
18	Raft River Geothermal Energy (MWh)	6,109.5	5,408.3	5,093.9	5,657.0	5,824.0	5,471.0	7,569.9	6,559.2	6,791.4	6,789.2	6,564.6	6,484.3	74,322.2
19	Total Energy Excl. CSPP (MWh)	80,415.8	54,245.7	174,889.8	179,066.0	202,317.7	139,379.5	85,235.1	149,424.0	123,729.1	156,601.6	59,984.7	84,881.1	1,490,170.2
20	Market Expense ($ x 1000)	$ 830.1	$ 327.5	$ 3,314.2	$ 4,294.0	$ 4,974.7	$ 2,937.2	$ 1,130.6	$ 2,805.0	$ 2,085.1	$ 2,852.6	$ 337.9	$ 795.7	$ 26,684.5
21	Elkhorn Wind Expense ($ x 1000)	$ 987.5	$ 1,008.4	$ 1,346.8	$ 1,824.5	$ 1,814.3	$ 1,190.1	$ 1,297.1	$ 1,634.7	$ 1,801.4	$ 1,621.1	$ 1,398.3	$ 1,179.1	$ 17,103.3
22	Neal Hot Springs Expense ($ x 1000)	$ 1,062.2	$ 836.4	$ 1,181.9	$ 1,002.7	$ 1,152.2	$ 1,031.4	$ 1,181.1	$ 1,890.2	$ 2,440.2	$ 2,048.5	$ 1,822.4	$ 1,300.8	$ 16,950.0
23	Raft River Geothermal Expense ($ x 1000)	$ 278.4	$ 246.5	$ 315.8	$ 420.9	$ 433.3	$ 339.2	$ 469.3	$ 488.0	$ 505.3	$ 429.8	$ 415.5	$ 301.7	$ 4,643.7
24	Total Expense Excl. CSPP ($ x 1000)	$ 3,158.2	$ 2,418.8	$ 6,158.7	$ 7,542.1	$ 8,374.5	$ 5,497.9	$ 4,078.1	$ 6,817.9	$ 6,831.9	$ 6,951.9	$ 3,974.1	$ 3,577.4	$ 65,381.5
	Surplus Sales													
25	Energy (MWh)	55,882.1	121,674.7	8,832.6	4,534.8	5,352.7	6,895.7	33,095.4	4,545.4	24,019.0	10,154.4	94,798.2	62,289.2	432,074.2
26	Revenue Including Transmission Costs ($ x 1000)	$ 1,263.2	$ 2,539.2	$ 167.4	$ 102.5	$ 163.3	$ 165.4	$ 746.9	$ 113.9	$ 702.2	$ 278.9	$ 2,426.4	$ 1,411.5	$ 10,080.8
27	Transmission Costs ($ x 1000)	$ 55.9	$ 121.7	$ 8.8	$ 4.5	$ 5.4	$ 6.9	$ 33.1	$ 4.5	$ 24.0	$ 10.2	$ 94.8	$ 62.3	$ 432.1
28	Revenue Excluding Transmission Costs ($ x 1000)	$ 1,207.4	$ 2,417.6	$ 158.6	$ 98.0	$ 157.9	$ 158.5	$ 713.8	$ 109.4	$ 678.2	$ 268.7	$ 2,331.6	$ 1,349.2	$ 9,648.7
	Net Hedges													
29	Energy (MWh)	-	-	-	54,600.0	31,200.0	-	-	-	-	-	-	-	85,800.0
30	Cost($ X 1000)	$ -	$ -	$ -	$ 1,208.8	$ 1,099.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,308.0
31	Net Power Supply Expenses ($ x 1000)	$ 5,344.7	$ 3,724.9	$ 16,437.6	$ 29,638.9	$ 27,955.0	$ 17,721.4	$ 13,566.8	$ 18,057.7	$ 21,379.5	$ 16,866.5	$ 7,085.6	$ 9,471.8	**$ 187,250.5**
32	PURPA ($ x 1000)	$ 13,737.5	$ 15,842.2	$ 17,899.9	$ 20,578.4	$ 17,603.0	$ 14,582.1	$ 13,400.0	$ 13,420.4	$ 13,285.1	$ 11,173.2	$ 12,347.9	$ 11,021.4	$ 174,891.0
33	Total Net Power Supply Expenses ($ x 1000)	$ 19,082.2	$ 19,567.1	$ 34,337.5	$ 50,217.2	$ 45,558.0	$ 32,303.6	$ 26,966.8	$ 31,478.1	$ 34,664.6	$ 28,039.8	$ 19,433.5	$ 20,493.2	**$ 362,141.5**
34	Sales at Customer Level (In 000s MWH)	1,021.475	1,027.715	1,200.248	1,443.007	1,527.416	1,385.154	1,106.348	1,026.179	1,150.844	1,280.412	1,213.909	1,101.751	14,484.458
35	Hours in Month	720	744	720	744	744	720	744	720	744	744	696	744	8784
36	Unit Cost / MWH (for PCAM)	$18.68	$19.04	$28.61	$34.80	$29.83	$23.32	$24.37	$30.68	$30.12	$21.90	$16.01	$18.60	**$25.00**
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
37	Portion of Purchased Power considered HL I	**14.00%**	56.43%	61.72%	70.03%	43.22%	60.89%	65.00%	39.95%	17.88%	25.00%	12.91%	17.79%	
38	Purchased Power HL Price	26.08	25.92	26.91	33.14	34.96	30.44	26.96	28.78	32.47	30.70	28.94	25.25	
39	Portion of Surplus Sales considered HL Surp	**69.89%**	54.27%	13.37%	2.78%	76.44%	31.81%	45.76%	62.13%	83.44%	80.98%	72.32%	80.89%	
40	Surplus Sales HL Price	24.20	24.05	24.97	30.75	32.44	28.25	25.02	26.70	30.13	28.49	26.85	23.43	
	Light Load													
41	Portion of Purchased Power considered LL F	**86.00%**	43.57%	38.28%	29.97%	56.78%	39.11%	35.00%	60.05%	82.12%	75.00%	87.09%	82.21%	
42	Purchased Power LL Price	21.69	19.60	20.67	25.65	27.79	25.22	23.51	25.65	28.38	26.51	25.60	22.28	
43	Portion of Surplus Sales considered LL Surp	**30.11%**	45.73%	86.63%	97.22%	23.56%	68.19%	54.24%	37.87%	16.56%	19.02%	27.68%	19.11%	
44	Surplus Sales LL Price	18.91	17.09	18.03	22.37	24.24	22.00	20.50	22.37	24.75	23.12	22.32	19.43	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 293
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

Annual Power Cost Update for April 2015 – March 2016

March 20, 2015

ANNUAL POWER COST UPDATE
April 2015 - March 2016

Line		
	OCTOBER APCU	
1	Forecast of Normalized Sales (MWh)	14,484,458
2	Total Net Power Supply Expense	$339,496,868
3	October APCU Rate ($/MWh)	$23.44
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	14,484,458
5	Total Net Power Supply Expense	$362,141,482
6	March Forecast Rate ($/MWh)	$25.00
7	Sales Adjusted Forecast Power Cost Change	$22,595,754
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$21,465,967
10	**March Forecast Rate Adjustment ($/MWh)**	$1.48
11	**Combined Rate ($/MWh)**	$24.92

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 293
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

Revenue Spread for October Update and March Forecast

March 20, 2015

Idaho Power Company
Rate Spread Exhibit for October Update 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													
	2012 October Update APCU (UE 242): Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures													
42	2012 October Update APCU Cost of Service (UE 242)	$1,298,993	$427,230	$35,118	$223,454	$28,138	$5,025	$722	$310,094	$150,288	$117,706	$24	$1,163	$30
	2013 October Update APCU (UE 257): Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures													
43	2013 October Update APCU Cost of Service (UE 257)	$2,298,531	$755,972	$62,141	$395,395	$49,790	$8,891	$1,278	$548,703	$265,930	$208,278	$42	$2,058	$54
	2014 October Update APCU (UE 279): Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures													
44	2014 October Update APCU Cost of Service (UE 279)	-$837,437	-$275,428	-$22,640	-$144,056	-$18,140	-$3,239	-$465	-$199,912	-$96,888	-$75,883	-$15	-$750	-$19
	2015 October Update APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures													
45	2015 October Update APCU Cost of Service (Allocator -- Line 14)	$1,037,765	$341,314	$28,056	$178,517	$22,480	$4,014	$577	$247,734	$120,065	$94,035	$19	$929	$24
46	% Increase Required Due to APCU (Proposed) (Line 45/(Line 36)	2.49%	2.10%	1.75%	2.49%	2.74%	2.59%	0.51%	2.93%	3.60%	2.55%	1.88%	0.73%	1.84%
47	Proposed Combined Revenue Spread (Line 36 + Line 42 + Line 43 + Line 44 + Line 45)	$45,462,332	$17,467,369	$1,706,228	$7,826,741	$902,967	$169,688	$114,573	$9,352,229	$3,775,565	$4,033,725	$1,086	$130,758	$1,403
48	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
49	2015 October Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 45/Line 48))	1.596	1.717	1.572	1.562	1.489	1.417	1.192	1.383	1.619	2.016	1.478	1.194	1.480
50	**APCU Incremental Rate for 2015 October Update (Mills per kWh) (Line 48*(Column A:[Line 48/Line 51]))**	**1.620**	**1.799**	**1.605**	**1.509**	**1.302**	**1.556**	**1.282**	**1.637**	**1.303**	**1.868**	**2.656**	**0.970**	**1.171**
51	Loss-Adjusted 2015-2016 Normalized Sales (kWh)	640,595,652	189,752,682	17,484,465	118,300,685	17,270,319	2,579,991	449,841	151,293,305	92,142,373	50,336,277	7,178	957,896	20,640
52	Projected October Update APCU 2015-2016 Revenues (Line 50 * Line 51)	$1,037,765	$341,314	$28,056	$178,517	$22,480	$4,014	$577	$247,734	$120,065	$94,035	$19	$929	$24

Notes:
1 2015 October Update APCU Revenues = ($1.62)/MWh x 640,595.652 MWhs = **$ 1,037,765** (Line 52, Column A)
2 ($1.62) =$23.44 (2015 October Update) - $21.82 (2014 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													

2015 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	2015 March Forecast APCU Cost of Service (Allocator -- Line 14)	$948,082	$311,818	$25,631	$163,090	$20,537	$3,667	$527	$226,325	$109,689	$85,909	$17	$849	$22
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	2.27%	1.92%	1.60%	2.27%	2.50%	2.37%	0.47%	2.68%	3.29%	2.33%	1.71%	0.67%	1.68%
44	Proposed Combined Revenue Spread (Line 36 + Line 42)	$42,632,562	$16,530,098	$1,629,184	$7,336,521	$841,236	$158,664	$112,989	$8,671,935	$3,445,859	$3,775,497	$1,034	$128,207	$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	2015 March Forecast Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 42/Line 45))	1.458	1.568	1.437	1.427	1.360	1.295	1.089	1.263	1.479	1.842	1.350	1.091	1.352
47	APCU Incremental Rate for 2015 March Forecast (Mills per kWh) (Line 46*(Column A:[Line 45/Line 48]))	1.480	1.643	1.466	1.379	1.189	1.421	1.171	1.496	1.190	1.707	2.427	0.886	1.070
48	Loss-Adjusted 2015-2016 Normalized Sales (kWh)	640,595,652	189,752,682	17,484,465	118,300,685	17,270,319	2,579,991	449,841	151,293,305	92,142,373	50,336,277	7,178	957,896	20,640
49	Projected March Forecast APCU 2015-2016 Revenues (Line 47 * Line 48)	$948,082	$311,818	$25,631	$163,090	$20,537	$3,667	$527	$226,325	$109,689	$85,909	$17	$849	$22

Notes:

1 2015 March Forecast APCU Revenues = $1.48/MWh x 640,595.652 MWhs = $ 948,082 (Line 49, Column A)

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 293
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

Summary of Revenue Charge

March 20, 2015

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
October Update / March Forecast Filing
Effective June 1, 2015

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) [1]	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	13,613	189,752,682	$19,178,109	101.07	($234,724)	$18,943,385	99.83	(1.22%)
2	Small General Service	7	2,460	17,484,465	$1,873,898	107.18	($16,540)	$1,857,357	106.23	(0.88%)
3	Large General Service	9	950	138,150,995	$10,841,664	78.48	($157,266)	$10,684,398	77.34	(1.45%)
4	Dusk to Dawn Lighting	15	0	449,841	$111,618	248.13	($359)	$111,259	247.33	(0.32%)
5	Large Power Service	19	6	243,435,678	$15,270,682	62.73	($204,138)	$15,066,543	61.89	(1.34%)
6	Agricultural Irrigation Service	24	1,743	50,336,277	$5,015,535	99.64	($98,307)	$4,917,228	97.69	(1.96%)
7	Unmetered General Service	40	2	7,178	$696	97.02	($4)	$693	96.50	(0.53%)
8	Street Lighting	41	25	957,896	$155,954	162.81	($810)	$155,144	161.96	(0.52%)
9	Traffic Control Lighting	42	7	20,640	$1,976	95.74	($15)	$1,961	95.01	(0.76%)
10	Total Uniform Tariffs		18,806	640,595,652	$52,450,133	81.88	($712,164)	$51,737,969	80.77	(1.36%)
11	Total Oregon Retail Sales		18,806	640,595,652	$52,450,133	81.88	($712,164)	$51,737,969	80.77	(1.36%)

(1) Updated April 2015-March 2016 Test Year