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March 22, 2013

VIA ELECTRONIC AND U.S. MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: UE 257 In The Matter of IDAHO POWER COMPANY's 2013 Annual Power Cost Update

Attention Filing Center:

Enclosed for filing in the above-referenced matter is an original and five copies of the Direct Testimony of Scott Wright.

A copy of this filing has been served on all parties to the service list. Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Enclosures
cc: Service List

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 257

IN THE MATTER OF IDAHO POWER COMPANY'S 2013 ANNUAL POWER COST UPDATE	)
MARCH FORECAST	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

SCOTT WRIGHT

March 22, 2013

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 2013 Annual Power Cost Update ("APCU"). The 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 2013 through March 2014.

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

A. After the Company filed the October Update on October 24, 2012, the two intervening parties, Staff of the Public Utility Commission of Oregon ("Commission") and the Citizens' Utility Board of Oregon reviewed the filing. After several months of data requests and settlement workshops, all parties agreed on a 2013 October Update per-unit cost of $23.13 per megawatt hour ("MWh"). This agreement was memorialized in the form of a Partial Stipulation ("October Settlement") filed with the Commission on January 25, 2013.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's March Forecast for the 2013 APCU which is required 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 for an upcoming water year using the AURORA model. The water year corresponds with the APCU test period of April 2013 through March 2014.

Q. Have any additional resources been added to the Company's resource portfolio since last year's March Forecast?

A. Yes, two resources were added to the Company's resource portfolio since last year's March Forecast. The first resource added was the Langley Gulch power plant, which is a combined-cycle plant with 300 megawatts ("MW") of capacity during the summer and 330 MW of capacity during the winter. The second resource added was the Neal Hot Springs Geothermal Purchased Power Agreement ("PPA"), which provides 21 average megawatts ("aMW") over the forecast period.

Q. Did the per-unit cost agreed to in the October Settlement include generation costs and benefits from the Langley Gulch power plant and the Neal Hot Springs Geothermal PPA?

A. Yes.

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

A. The following variables are delineated 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 Northwest River Forecast Center ("NRFC") in Portland, Oregon, and current reservoir levels;

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

h. Forward price curve as defined below;

i. PURPA contract expenses; and

j. The Oregon state allocation factor.

Q. 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 2013 through March 2014 test period the only variables that have changed from the October APCU are: (1) fuel prices; (2) the forecast of hydro conditions from the NRFC; (3) known power purchases and surplus sales resulting from the Company's Risk Management Policy; (4) the forward price curve in accordance with Order No. 08-238; and (5) PURPA contract expenses.

Q. Please explain what variables related to fuel prices have changed since the October Update?

A. The coal price forecast and the gas price forecast used in the October Update were updated in accordance with Order No. 08-238 as described above. The Company routinely updates this information for operational planning purposes. Since the time the October Update was filed, newer operational forecasts have become available, which include an updated coal and gas price forecast.

Q. How did the updated coal price forecast impact the per-unit cost of output for the Company's coal plants as compared to the October Update?

A. The per-unit cost of output from AURORA in terms of dollars per MWh increased slightly at the Jim Bridger power plant ("Bridger") from $22.93 per MWh to $23.33 per MWh, while decreasing slightly at the Boardman power plant ("Boardman") from $22.74 per MWh to $22.56 per MWh and increasing at the Valmy power plant ("Valmy") from $37.59 per MWh to $39.15 per MWh. The output cost from 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 coal price forecast since the October Update was filed?

A. The coal prices shown above are in dollars per MWh, so these costs include any start up costs over the period of the forecast year, as well as any fixed costs related to the variable cost of production. The slight increase in the per-unit cost of coal for the Bridger plant is attributed to updated prices for Bridger Coal Company for the 2013 time period. The forecast used for the October Update contained estimated 2013 prices for Bridger Coal Company, whereas this forecast reflects the most recent estimates. The decrease in the per-unit cost of coal for the Boardman plant can be attributed to reduced volumes of higher priced spot purchases of coal which are not contracted for. Lower priced contract coal replaced some of the spot purchases that were forecasted in the October Update, thereby reducing the overall cost. The increase in the per-unit cost of coal for Valmy can be attributed to lower output for the plant. That is, costs that do not vary with annual fluctuations in output or "fixed costs" are spread over fewer units of output, resulting in a higher per-unit cost of output.

In previous years' filings, a concern over including fixed costs with variable costs in the APCU has been raised. The fixed costs described above are included in the Federal Energy Regulatory Commission ("FERC") Account 501, Fuel. These costs include: oil consumption, administrative and general, and fuel handling costs. According to the FERC Uniform System of Accounts, each of these cost categories is associated with the variable cost of fuel used in the production of steam for the generation of electricity. While the Company may characterize some of these costs as being "fixed" in nature in the context of the annual APCU filing, they are actually variable costs over time and considered to be variable by the FERC.

Q. How did the gas price 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 $3.69 per MMBtu, while the gas price forecast used for the March Forecast for Henry Hub is $3.62 per MMBtu, a slight decrease of $0.07 per MMBtu. The Henry Hub gas price is used as a reference fuel in the AURORA model. A reference fuel allows for one gas price to be input into the AURORA model, which then has a corresponding effect on multiple gas prices (Sumas or other gas prices in the Northwest) within the AURORA model based on predetermined weighting factors for each gas price index.

Q. Which water supply forecast from the NRFC was used to create the hydro generation forecast for the March Forecast?

A. The forecast monthly hydro generation levels included in the March Forecast reflect the NRFC's March 8, 2013, forecast ("March 8th Forecast") and current reservoir levels. The March 8th Forecast has expected inflows into Brownlee Reservoir for April through July of 3.74 million acre-feet ("MAF"), or 68 percent of the new 30-year (1981-2010) average level of 5.47 MAF.

Q. Please explain how the "68 percent of the new 30-year (1981-2010) average level of 5.47 MAF" should be viewed in relation to the prior measure of average.

A. Historically the 30-year average time period was (1971-2000); however, earlier this year, the Army Corp of Engineers updated their 30-year average to include the (1981-2010) time period. The previous 30-year average was 6.15 MAF (1971-2000), while the new 30-year average is 5.47 MAF (1981-2010), a decrease of 0.68 MAF. This new lower average suggests that the 30-year period of 1981-2010 was generally a dryer period than the prior period of 1971-2000, and therefore, the baseline view of "average" has been adjusted downward.

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 5.21 MAF. While last year's forecast was for below average streamflows, this year's forecast is lower than last year's forecast by 1.47 MAF (5.21 MAF – 3.74 MAF = 1.47 MAF), resulting in streamflows even further below average.

Q. What significance does a lower 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 stream flow forecast has a detrimental effect on the Company's variable power supply expenses. For example, the hydro generation forecasted under the normalized scenario for the October Settlement was 8.5 million MWh, while the hydro generation forecasted under this year's March Forecast is 7.1 million MWh, a decrease of 1.4 million MWh or 169 aMW.

The lower forecast hydro generation used for the March Forecast resulted in the following impacts to Net Power Supply Expenses ("NPSE"): (1) market purchased power volumes in AURORA increased by 47,167 MWh over the levels included in the October Settlement; (2) known power purchases and surplus sales from the Company's Risk Management Policy account for 393,792 MWh of additional purchased power; (3) base load generation remained relatively stable between the October Settlement and March Forecast; and finally, (4) surplus sales volumes, which are a direct benefit to customers decreased by 1.2 million MWh as compared to the October Settlement level.

Because market purchased power and surplus sales volumes were repriced using different forward price curves, a comparison of the expenses between the October Settlement and March Forecast was not performed.

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

A. Exhibit No. 201 shows the March 12, 2013, Mid-Columbia price curve for the April 2013 through March 2014 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, five PURPA projects that were forecast to be online during the April 2013 through March 2014 test period have terminated their agreements or are now expected to be terminated. When the October Update was filed, there were 109 PURPA contracts, whereas the March Forecast includes 104 PURPA contracts.

Q. Was the Dynamis PURPA contract one of the five contracts removed from the March Forecast?

A. Yes. Since the October Settlement was signed, Ada County and Dynamis terminated their agreement to build a waste to energy facility. The Company subsequently filed a motion with the Idaho Public Utilities Commission ("Idaho Commission") on March 7, 2013 for approval of a settlement agreement to terminate the Dynamis PURPA contract. The Idaho Commission approved the contract termination and settlement agreement on March 19, 2013, in Order No. 32763. In light of these changing circumstances, the Company has removed the entire Dynamis PURPA contract generation and expense from the March Forecast computations.

Q. How does the total PURPA expense included in this year's March Forecast compare to the level of total PURPA expense included in last year's March Forecast?

A. The total PURPA expense included in this year's March Forecast is $161.5 million compared to the $192.0 million included in last year's March Forecast, a decrease of $30.5 million.

Q. What is the Company's March Forecast of net power supply expense as a result of updating fuel prices, updating water conditions to reflect the most current NRFC, including known purchases and sales using the most current forward price curves as per Order No. 08-238, and modifying PURPA contract expenses?

A. Exhibit No. 202 shows the results of a single water condition for the April 2013 through March 2014 test period, with updated fuel prices, updated stream flow conditions and reservoir levels, updated power purchases and surplus sales from the Company's Risk Management Policy (Net Hedges), market purchased power and surplus sales repriced pursuant to Order No. 08-238, and updated PURPA contract expenses. The March Forecast for net power supply expense without PURPA is $196.9 million. When PURPA expenses of $161.5 million are included, the total net power supply expense for the March Forecast is $358.4 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 2013 through March 2014 test period are 14,061,686 MWh. Based upon test period sales, the cost per-unit for the March Forecast to become effective on June 1, 2013, is $25.49 per MWh ($358.4 million / 14.062 million MWh = $25.49 per MWh).

Q. How does this $25.49 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 2012 through March 2013 test period was $20.83 per MWh, as compared to this year's April 2013 through March 2014 test period of $25.49 per MWh, an increase of $4.66 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 Settlement rate of $23.13 per MWh. Lines 4-6 show the calculation for the March Forecast Rate of $25.49 per MWh. Line 7 is calculated by the March Forecast Rate minus the October APCU 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 $2.24 per MWh.

Q. Please explain how the incremental revenue requirement for the March Forecast is calculated using the March Forecast Rate Adjustment unit cost of $2.24 per MWh.

A. The incremental revenue requirement for the March Forecast is calculated by multiplying the unit cost of $2.24 per MWh by the loss adjusted Oregon jurisdictional sales for the April 2013 through March 2014 test period of 628,013.895 MWh creating a revenue deficiency of $1.4 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 2013 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 204.

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

A. Yes. The Company revised the revenue spread for the October Settlement to align with the loss adjusted sales that were used for the March Forecast filing. This practice of updating the revenue spread for the October Update is consistent with the method applied in last year's APCU filing. The loss adjusted sales used for the October Settlement were 30,326 MWh higher than the loss adjusted sales used for the March Forecast filing (30,326 MWh = October Settlement 658,340.684 MWh – March Forecast 628,013.895 MWh). The change in loss adjusted sales decreases the October Settlement revenue requirement by $110,996 ($110,996 = October Settlement of $2,409,527 – Updated October Settlement to reflect new loss adjusted sales of $2,298,531). Exhibit 204 also shows the revised revenue spread for the October Settlement.

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

A. The overall revenue impact of this year's combined October Settlement and March Forecast is an increase of approximately $2.9 million or 6.03 percent overall. The $2.9 million increase reflects the $3.7 million associated with the 2013 APCU (October Settlement and March Forecast) less the $0.8 million currently included in Oregon customers' rates related to the 2012 APCU.

Q. Have you supervised the preparation of an exhibit showing the summary of revenue impact resulting from the combined October Settlement and March Forecast proposed by the Company?

A. Yes. Exhibit No. 205 provides a summary of the revenue change resulting from this year's combined October Settlement and March Forecast as compared to current revenue. The revenue amount shown on Exhibit No. 205 may differ slightly from the revenue requirement amounts shown on Exhibit No. 204 because of rounding in the rate design process. For example, Exhibit No. 204 shows a cents per kWh for Schedule 41, Municipal Street Lights. However, in the rate design process, this amount is converted to a cents-per-lamp charge. The end result is a slight difference from the revenue requirement amount shown on Exhibit No. 204.

Q. Has the Company filed tariff sheets that reflect the proposed change?

A. Yes. The Company is concurrently filing Advice No. 13-07 with this filing, which contains all of the affected tariffs, with an effective date of June 1, 2013.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 257
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

March 12, 2013, Mid-Columbia Price Curve for April 2013 – March 2014

March 22, 2013

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	**3/12/2013**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**
2	**mc HL**	26.70	23.00	20.50	35.50	40.30	37.50	34.10	36.45	38.90	37.68	38.28	35.10
3	**mc LL**	20.20	13.00	6.00	20.40	28.15	29.55	29.70	31.45	33.90	31.86	31.29	29.84
4	**Reallocated Prices**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**
5	**HL PP**												
6	103.9%	27.74	23.90	21.30	36.88	41.87	38.96	35.43	37.87	40.42	39.15	39.78	36.47
7	**LL PP**												
8	107.1%	21.63	13.92	6.43	21.85	30.15	31.65	31.81	33.68	36.31	34.12	33.51	31.96
9	**HL SS**												
10	96.4%	25.74	22.17	19.76	34.22	38.85	36.15	32.87	35.14	37.50	36.33	36.90	33.83
11	**LL SS**												
12	93.4%	18.87	12.14	5.60	19.05	26.29	27.60	27.74	29.37	31.66	29.75	29.22	27.87

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 257
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

Power Supply Costs for April 1, 2013 – March 31, 2014

March 22, 2013

IPCO POWER SUPPLY COSTS FOR APRIL 1, 2013 -- MARCH 31, 2014 (One Hydro Condition)
Repriced Using UE195 Settlement Methodology - March Forecast

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	627,080.9	844,981.0	736,716.7	562,324.2	466,167.2	459,681.0	499,980.2	414,344.0	499,286.2	469,622.6	708,473.0	772,244.2	7,060,901.2
Bridger													
Energy (MWh)	141,727.2	198,419.1	245,264.7	419,784.8	427,137.7	401,773.5	382,012.3	376,037.5	417,508.1	414,299.0	243,319.4	219,152.0	3,886,435.2
Cost ($ x 1000)	$ 3,503.8	$ 4,916.6	$ 5,907.7	$ 9,563.8	$ 9,716.1	$ 9,162.8	$ 8,781.6	$ 8,629.8	$ 9,516.7	$ 9,618.7	$ 5,929.1	$ 5,426.8	$ 90,673.5
Boardman													
Energy (MWh)	15,416.1	7,729.1	26,739.5	41,682.9	41,682.9	40,338.3	41,664.6	40,338.3	41,682.9	17,961.2	12,108.1	13,413.8	340,757.9
Cost ($ x 1000)	$ 343.8	$ 180.1	$ 583.9	$ 865.9	$ 865.9	$ 838.0	$ 865.6	$ 838.0	$ 865.9	$ 568.5	$ 413.0	$ 457.4	$ 7,686.2
Valmy													
Energy (MWh)	2,111.7	24,339.0	46,278.0	85,771.8	89,781.4	62,835.3	64,933.1	61,686.5	67,097.6	61,686.5	50,864.3	40,415.9	657,801.0
Cost ($ x 1000)	$ 82.8	$ 951.4	$ 1,808.3	$ 3,215.3	$ 3,342.6	$ 2,439.0	$ 2,537.3	$ 2,410.5	$ 2,621.9	$ 2,558.9	$ 2,110.0	$ 1,675.6	$ 25,753.6
Langley Gulch													
Energy (MWh)	114,840.0	114,739.7	104,133.5	144,230.9	148,491.9	125,598.1	118,644.6	116,336.7	130,314.8	123,952.6	110,880.0	120,714.0	1,472,876.9
Cost ($ x 1000)	$ 2,978.4	$ 2,899.3	$ 2,660.9	$ 3,697.3	$ 3,840.9	$ 3,332.2	$ 3,281.5	$ 3,641.3	$ 4,416.8	$ 4,167.0	$ 3,625.3	$ 3,783.6	$ 42,324.5
Danskin													
Energy (MWh)	-	-	-	2,230.4	1,253.5	2.3	-	-	-	-	-	-	3,486.2
Cost ($ x 1000)	$ -	$ -	$ -	$ 86.8	$ 49.4	$ 0.1	$ -	$ -	$ -	$ -	$ -	$ -	$ 136.3
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 466.9	$ 478.2	$ 476.2	$ 498.4	$ 499.8	$ 484.4	$ 481.3	$ 738.2	$ 759.6	$ 760.8	$ 714.1	$ 760.8	$ 7,118.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	206.9	3,271.9	71,411.6	66,515.0	78,337.0	63,916.1	344.1	1,587.5	65,450.6	92,171.2	25.4	-	443,237.1
Elkhorn Wind (MWh)	25,157.1	24,359.9	22,205.9	24,381.8	22,234.7	18,612.6	22,852.0	29,175.9	30,540.1	25,731.5	24,233.9	23,856.9	293,342.3
Raft River Geothermal (MWh)	5,721.8	6,127.8	5,457.5	5,652.9	6,022.4	5,630.1	6,353.4	6,552.1	6,805.1	6,426.1	5,975.6	6,723.0	73,447.8
Neil Hot Springs Geothermal (MWh)	15,808.6	16,335.6	15,808.6	16,335.6	16,335.6	15,808.6	16,335.6	15,808.6	16,335.6	7,796.5	14,754.7	16,335.6	183,799.1
Total Energy Excl. CSPP (MWh)	46,894.4	50,095.2	114,883.5	112,885.2	122,929.7	103,967.5	45,885.1	53,124.0	119,131.3	132,125.3	44,989.6	46,915.5	993,826.4
Market Cost ($ x 1000)	$ 5.7	$ 78.2	$ 1,360.0	$ 2,276.3	$ 2,898.1	$ 2,477.9	$ 12.2	$ 59.0	$ 2,482.1	$ 3,407.1	$ 0.9	$ -	$ 15,057.6
Elkhorn Wind Cost ($ x 1000)	$ 1,059.8	$ 1,026.2	$ 1,272.7	$ 1,676.9	$ 1,529.2	$ 1,066.8	$ 1,309.8	$ 2,006.6	$ 2,100.5	$ 1,519.0	$ 1,430.6	$ 1,035.2	$ 17,033.3
Raft River Geothermal Cost ($ x 1000)	$ 250.1	$ 267.8	$ 324.6	$ 403.4	$ 429.8	$ 334.8	$ 377.8	$ 467.6	$ 485.6	$ 390.2	$ 362.8	$ 300.0	$ 4,394.7
Neil Hot Springs Geothermal Cost ($ x 1000)	$ 1,147.2	$ 1,185.4	$ 1,565.1	$ 1,940.7	$ 1,940.7	$ 1,565.1	$ 1,617.2	$ 1,878.1	$ 1,940.7	$ 801.3	$ 1,516.5	$ 1,230.7	$ 18,328.5
Total Cost Excl. CSPP ($ x 1000)	$ 2,462.8	$ 2,557.6	$ 4,522.4	$ 6,297.3	$ 6,797.8	$ 5,444.6	$ 3,317.0	$ 4,411.3	$ 7,008.9	$ 6,117.7	$ 3,310.8	$ 2,565.9	$ 54,814.0
Surplus Sales													
Energy (MWh)	104,980.8	245,382.8	65,602.9	75,793.4	36,406.1	132,814.8	282,449.6	128,020.1	16,183.6	8,903.0	203,554.6	264,209.3	1,564,300.8
Revenue Including Transmission Costs ($ x 1000)	$ 2,301.2	$ 4,155.7	$ 658.8	$ 1,832.3	$ 1,252.0	$ 3,849.1	$ 8,605.6	$ 4,126.2	$ 569.1	$ 295.6	$ 6,879.9	$ 8,216.2	$ 42,741.7
Transmission Costs ($ x 1000)	$ 105.0	$ 245.4	$ 65.6	$ 75.8	$ 36.4	$ 132.8	$ 282.4	$ 128.0	$ 16.2	$ 8.9	$ 203.6	$ 264.2	$ 1,564.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,196.2	$ 3,910.3	$ 593.2	$ 1,756.5	$ 1,215.6	$ 3,716.3	$ 8,323.1	$ 3,998.2	$ 552.9	$ 286.7	$ 6,676.3	$ 7,952.0	$ 41,177.4
Net Hedges													
Energy (MWh)	-	-	-	241,800.0	151,992.0	-	-	-	-	-	-	-	393,792.0
Cost($ X 1000)	$ -	$ -	$ -	$ 6,143.0	$ 3,771.2	$ (312.3)	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,601.9
Net Power Supply Costs ($ x 1000)	$ 7,642.2	$ 8,073.0	$ 15,366.2	$ 28,611.4	$ 27,668.2	$ 17,672.4	$ 10,941.2	$ 16,670.8	$ 24,636.9	$ 23,504.8	$ 9,426.0	$ 6,718.1	**$ 196,931.2**
PURPA ($ x 1000)	$ 12,020.6	$ 15,448.5	$ 17,208.4	$ 17,792.2	$ 15,354.3	$ 14,008.4	$ 13,103.1	$ 13,869.7	$ 11,177.5	$ 11,449.9	$ 10,353.2	$ 9,728.1	$ 161,513.9
Total Net Power Supply Expense ($ x 1000)	$ 19,662.8	$ 23,521.5	$ 32,574.6	$ 46,403.6	$ 43,022.5	$ 31,680.9	$ 24,044.3	$ 30,540.5	$ 35,814.4	$ 34,954.7	$ 19,779.1	$ 16,446.1	**$ 358,445.0**
Sales at Customer Level (In 000s MWH)	1,000.535	1,001.776	1,167.710	1,395.693	1,474.793	1,342.353	1,077.825	1,005.193	1,135.660	1,249.058	1,152.265	1,058.826	14,061.686
Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
Unit Cost / MWH (for PCAM)	$19.65	$23.48	$27.90	$33.25	$29.17	$23.60	$22.31	$30.38	$31.54	$27.98	$17.17	$15.53	**$25.49**
Prices Used in Purchased Power & Surplus Sales Above:													
Heavy Load													
Portion of Purchased Power considered HL F	**97.31%**	**100.00%**	**84.84%**	**82.29%**	**58.40%**	**97.35%**	**99.94%**	**83.39%**	**39.34%**	**56.55%**	**0.00%**	**0.00%**	
Purchased Power HL Price	27.74	23.90	21.30	36.88	41.87	38.96	35.43	37.87	40.42	39.15	39.78	36.47	
Portion of Surplus Sales considered HL Surpl	**44.43%**	**47.79%**	**31.35%**	**33.76%**	**64.48%**	**16.15%**	**53.15%**	**49.57%**	**60.04%**	**52.45%**	**59.56%**	**54.09%**	
Surplus Sales HL Price	25.74	22.17	19.76	34.22	38.85	36.15	32.87	35.14	37.50	36.33	36.90	33.83	
Light Load													
Portion of Purchased Power considered LL P	**2.69%**	**0.00%**	**15.16%**	**17.71%**	**41.60%**	**2.65%**	**0.06%**	**16.61%**	**60.66%**	**43.45%**	**100.00%**	**0.00%**	
Purchased Power LL Price	21.63	13.92	6.43	21.85	30.15	31.65	31.81	33.68	36.31	34.12	33.51	31.96	
Portion of Surplus Sales considered LL Surpl	**55.57%**	**52.21%**	**68.65%**	**66.24%**	**35.52%**	**83.85%**	**46.85%**	**50.43%**	**39.96%**	**47.55%**	**40.44%**	**45.91%**	
Surplus Sales LL Price	18.87	12.14	5.60	19.05	26.29	27.60	27.74	29.37	31.66	29.75	29.22	27.87	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 257
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

Annual Power Cost Update for April 2013 – March 2014

March 22, 2013

ANNUAL POWER COST UPDATE
April 2013 - March 2014

Line		
	OCTOBER APCU	
1	Forecast of Normalized Sales (MWh)	14,061,686
2	Total Net Power Supply Expense	$325,178,267
3	October APCU Rate ($/MWh)	$23.13
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	14,061,686
5	Total Net Power Supply Expense	$358,445,038
6	March Forecast Rate ($/MWh)	$25.49
7	Sales Adjusted Forecast Power Cost Change	$33,185,579
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$31,526,300
10	**March Forecast Rate Adjustment ($/MWh)**	$2.24
11	**Combined Rate ($/MWh)**	$25.37

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 257
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

Rate Spread for October Update and March Forecast

March 22, 2013

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: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures													
43	2013 October Update APCU Cost of Service (Allocator -- Line 14)	$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
44	% Increase Required Due to APCU (Proposed) (Line 43/(Line 36)	5.51%	4.66%	3.88%	5.51%	6.07%	5.74%	1.14%	6.50%	7.97%	5.65%	4.16%	1.62%	4.07%
45	Proposed Combined Revenue Spread (Line 36 + Line 42 + Line 43)	$45,282,004	$17,401,482	$1,700,812	$7,792,280	$898,628	$168,913	$114,462	$9,304,407	$3,752,388	$4,015,572	$1,082	$130,578	$1,399
46	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
47	2013 October Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 43/Line 46))	3.535	3.802	3.483	3.461	3.298	3.139	2.640	3.062	3.586	4.465	3.274	2.645	3.278
48	**APCU Incremental Rate for 2013 October Update (Mills per kWh) (Line 47*{Column A:[Line 46/Line 49]})**	**3.660**	**4.044**	**3.499**	**3.464**	**3.271**	**3.453**	**2.726**	**3.091**	**3.863**	**4.768**	**3.897**	**2.502**	**2.578**
49	*Loss-Adjusted 2013-2014 Normalized Sales (kWh)*	628,013,895	186,917,771	17,759,679	114,159,396	15,222,890	2,574,944	468,706	177,539,312	68,837,366	43,679,700	10,836	822,531	20,764
50	Projected October Update APCU 2013-2014 Revenues (Line 48 * Line 49)	$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

Notes:

1 **2013 October Update APCU Revenues = $3.66/MWh x 628,013.895 MW's =** **$ 2,298,531** **(Line 42, Column A)**

2 **$3.66 = $23.13 (2013 October APCU Rate) - $19.47 (2012 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													

2013 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	2013 March Forecast APCU Cost of Service (Allocator -- Line 14)	$1,406,751	$462,671	$38,032	$241,990	$30,473	$5,442	$782	$335,818	$162,755	$127,470	$26	$1,259	$33
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	3.37%	2.85%	2.37%	3.37%	3.71%	3.51%	0.70%	3.98%	4.88%	3.45%	2.54%	0.99%	2.49%
44	Proposed Combined Revenue Spread (Line 36 + Line 42)	$43,091,232	$16,680,951	$1,641,585	$7,415,422	$851,172	$160,439	$113,244	$8,781,428	$3,498,925	$3,817,059	$1,042	$128,617	$1,348
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	2013 March Forecast Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 42/Line 45))	2.164	2.327	2.131	2.118	2.018	1.921	1.616	1.874	2.195	2.733	2.004	1.619	2.006
47	**APCU Incremental Rate for 2013 March Forecast (Mills per kWh) (Line 46*{Column A:[Line 45/Line 48]})**	**2.240**	**2.475**	**2.141**	**2.120**	**2.002**	**2.113**	**1.668**	**1.892**	**2.364**	**2.918**	**2.385**	**1.531**	**1.578**
48	*Loss-Adjusted 2013-2014 Normalized Sales (kWh)*	628,013,895	186,917,771	17,759,679	114,159,396	15,222,890	2,574,944	468,706	177,539,312	68,837,366	43,679,700	10,836	822,531	20,764
49	Projected March Forecast APCU 2013-2014 Revenues (Line 47 * Line 48)	$1,406,751	$462,671	$38,032	$241,990	$30,473	$5,442	$782	$335,818	$162,755	$127,470	$26	$1,259	$33

Notes:

1 **2013 March Forecast APCU Revenues = $2.24/MWh x 628,013.895 MW's =** **$ 1,406,751** **(Line 42, Column A)**

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 257
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

Summary of Revenue Charge

March 22, 2013

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2013

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	13,448	186,917,771	$17,797,877	95.22	$951,823	$18,749,700	100.31	5.35%
2	Small General Service	7	2,462	17,759,679	$1,814,725	102.18	$78,090	$1,892,815	106.58	4.30%
3	Large General Service	9	909	131,957,232	$9,718,922	73.65	$565,860	$10,284,782	77.94	5.82%
4	Dusk to Dawn Lighting	15	0	468,706	$114,360	243.99	$1,634	$115,995	247.48	1.43%
5	Large Power Service	19	7	246,376,678	$14,409,389	58.49	$1,017,779	$15,427,168	62.62	7.06%
6	Agricultural Irrigation Service	24	1,605	43,679,700	$4,013,880	91.89	$278,935	$4,292,815	98.28	6.95%
7	Unmetered General Service	40	2	10,836	$980	90.45	$55	$1,035	95.56	5.64%
8	Street Lighting	41	21	822,531	$137,760	167.48	$2,580	$140,340	170.62	1.87%
9	Traffic Control Lighting	42	7	20,764	$1,917	92.30	$62	$1,978	95.28	3.22%
10	Total Uniform Tariffs		18,461	628,013,897	$48,009,809	76.45	$2,896,819	$50,906,628	81.06	6.03%
12	Total Oregon Retail Sales		18,461	628,013,897	$48,009,809	76.45	$2,896,819	$50,906,628	81.06	6.03%

(1) Updated April 2013-March 2014 Test Year

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket UE 257 on the following named person(s) on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

OPUC Dockets
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DATED: March 22, 2013

Wendy McIndoo

Wendy McIndoo
Office Manager

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