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March 22, 2012

VIA ELECTRONIC AND U.S. MAIL

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

Re: UE 242 - In The Matter of IDAHO POWER COMPANY's 2012 Annual Power Cost Update

Attention Filing Center:

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

A copy of this filing has been served on all parties to this proceeding as indicated on the attached Certificate of Service. Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Enclosures
cc: Service List

Idaho Power/200
Witness: Scott Wright

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UE 242

IN THE MATTER OF IDAHO POWER COMPANY'S 2012 ANNUAL POWER COST UPDATE	)
MARCH FORECAST	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

SCOTT WRIGHT

March 22, 2012

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 2012 Annual Power Cost Update ("APCU"). The October Update is Idaho Power Company's ("Idaho Power" or "Company") estimate of what "normalized" power supply expenses will be for the upcoming APCU test period of April 2012 through March 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 2012 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 2012 through March 2013.

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

A. Yes. The Langley Gulch power plant has been included in this year's March Forecast. Langley Gulch is a 300 megawatt combined-cycle natural gas plant currently under construction. It is expected to be commercially available or "on-line" in July 2012, during the April 2012 through March 2013 test period. The generation from the Langley Gulch power plant was also included in the October Update.

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 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. Public Utility Regulatory Policies Act of 1978 ("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 2012 through March 2013 test period the only variables that have changed from the October APCU are: (1) fuel prices; (2) the forecast of normalized sales and loads; (3) the forecast of hydro conditions from the Northwest River Forecast Center; (4) known power purchases and surplus sales resulting from the Company's Risk Management Policy; and (5) the forward price curve in accordance with Order No. 08-238.

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 megawatt-hour ("MWh") increased at the Jim Bridger power plant ("Bridger") from $22.54 per MWh to $24.27 per MWh, while decreasing at the Boardman power plant ("Boardman") and Valmy power plant ("Valmy") from $20.40 per MWh to $19.93 per MWh and $34.76 per MWh to $31.16 per MWh, respectively. The output cost from AURORA includes all fuel cost components including any start up costs.

Q. What factors drove the changes in the coal price forecast since the October Update was filed?

A. The updated coal price forecast reflects a per ton cost of coal increase for Bridger which was driven by two primary factors: (1) a forecast of lower 2012 plant utilization and (2) an increase in the cost of coal in inventory. The updated Bridger Mine mining plan incorporates a forecast of lower 2012 plant demands, which has consequently reduced the projected deliveries from the Bridger Mine. Because the Bridger Mine does not experience a corresponding reduction in operations and maintenance ("O&M") costs in the near-term, the projected per ton coal cost for Bridger in 2012 has increased, as O&M costs are expected to be spread over fewer units of output. The updated Bridger Mine mining plan reflects higher than projected 2011 actual mine costs, which has increased the cost of coal in the mine inventory over levels previously forecasted.

The cost decrease at Valmy was related to the availability of lower cost force majeure coal carried over from the previous year. The cost decrease for Boardman was the result of lower than expected coal contract prices as compared to those assumed in last fall's forecast. The contracting for the 2012 Boardman coal supply was not completed until the fall of 2011 and costs for 2012 were projected based on the 2011 contract price. The 2012 contracted price was ultimately lower than the 2011 projection.

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

A. As has been the trend in recent years, increased supply and lower demand for natural gas has further driven down the price of natural gas since the October Update was filed. The gas price used in the October Update for Henry Hub was $4.60 per MMBtu, while the gas price used for the March Forecast for Henry Hub is $3.47 per MMBtu, a decrease of $1.13 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. Please explain why the forecast of normalized sales and loads were updated from the October Update.

A. Since the October Update was filed, the Company completed an updated forecast of normalized sales and load. The updated forecast also includes a revised sales and load schedule for special contract customer Hoku Materials, Inc. ("Hoku"). The load used for the March Forecast was 1,746 average megawatts ("aMW"), 95 aMW lower than the forecast used in the October Update, of 1,841 aMW.

Q. What modifications have been made to the Hoku contract since the October Update?

A. The Company and Hoku agreed to reform the Hoku contract which was memorialized in a settlement stipulation that was approved by the Idaho Public

Utilities Commission ("Commission"), Final Order No. 32486 issued on March 15, 2012. The reformed contract reduces Hoku's monthly minimum payment to $800,000 per month for the period January 1, 2012, through June 30, 2013, thereby reducing the first block revenues that were treated similarly to surplus sales revenue. The Hoku load included in the October Update was 67 aMW. The Hoku load included in the March Forecast was reduced by 55 aMW to 12 aMW to reflect load expectations consistent with the Commission-approved terms of the revised special contract to be filed with the Commission on or before April 13, 2012.

Q. Which water supply forecast from the Northwest River Forecast Center 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 Northwest River Forecast Center's March 6, 2012, forecast ("March 6th Forecast") and current reservoir levels of monthly hydro generation. The March 6th Forecast has expected inflows into Brownlee Reservoir for April through July to be 5.21 million acre-feet ("MAF"), or 83 percent of the 30-year (1971-2000) average level of 6.31 MAF.

Q. How does the March 6th water supply Forecast compare to last year's March 7, 2011, Northwest River Forecast Center's forecast?

A. The Northwest River Forecast Center's forecast used in last year's March Forecast was 5.7 MAF or 90 percent of the 30-year average. While last year's forecast was for below average streamflows, this year's forecast is slightly lower than last year's forecast by 0.49 MAF (5.7 MAF – 5.21 MAF = 0.49 MAF).

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

A. Exhibit 201 shows the March 8, 2012, mid-Columbia price curve for the April 2012 through March 2013 test period the Company used pursuant to Order No. 08-238.

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

A. Exhibit 202 shows the results of a single water condition for the April 2012 through March 2013 test period, with updated fuel prices, updated normalized sales and loads, updated stream flow conditions and reservoir levels, updated power purchases and surplus sales from the Company's Risk Management Policy (Net Hedges), and market purchased power and surplus sales repriced pursuant to Order No. 08-238. The March Forecast for net power supply expense without PURPA is $98.4 million. When PURPA expense of $192.0 million is included, the total net power supply expense for the March Forecast is $290.4 million.

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

A. The PURPA expense included in this year's March Forecast is $192.0 million compared to the $129.1 million included in last year's March Forecast, an increase of $62.9 million.

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

A. Exhibit 202 shows the normalized annual sales at the customer level for the April 2012 through March 2013 test period are 13,919,970 MWh. Based upon test period sales, the cost per unit for the March Forecast to become effective on June 1, 2012, is $20.86 per MWh ($290.4 million / 13.919 million MWh = $20.86 per MWh).

Q. How does this $20.86 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 2011 through March 2012 test period was $18.03 per MWh, as compared to this year's April 2012 through March 2013 test period of $20.86 per MWh.

Q. Please describe the calculation necessary to determine the March Forecast rate adjustment.

A. Exhibit 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 APCU rate of $18.98 per MWh. Lines 4-6 show the calculation for the March Forecast rate of $20.86 per MWh. Line 7 is calculated by subtracting the March Forecast rate from 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 $1.79 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 $1.79 per MWh.

A. The incremental revenue requirement for the March Forecast is calculated by multiplying the unit cost of $1.79 per MWh by the loss adjusted Oregon jurisdictional sales for the April 2012 through March 2013 test period of 643,065.633 MWh creating a revenue deficiency of $1.2 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 incremental revenue requirement associated with the 2012 March Forecast according to the revenue spread methodology approved by the Commission in Docket No. UE 214, Order No. 10-191. Order No. 10-191 established a revenue spread methodology whereby the revenue requirement 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, Docket No. 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 Docket No. UE 233 is shown on Exhibit 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 reflect the new loss adjusted sales that were used for the March Forecast filing. The loss adjusted sales used for the October Update were 16,285.040 MWh higher than the loss adjusted sales used for the March Forecast filing (16,285.040 MWh = October Update 659,350.677 MWh – March Forecast 643,065.633 MWh). The change in loss adjusted sales reduces the Oregon jurisdictional allocation of the October Update incremental revenue requirement by $32,895. The Company also updated the revenue spread for the October Update to reflect the stipulated revenue spread methodology approved in Docket No. UE 233, consistent with that used for the

March Forecast. Exhibit 204 also shows the revised revenue spread for the October Update.

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. The overall revenue impact of this year's combined October Update and March Forecast is an increase of approximately $1.8 million or 4.05 percent overall. The $1.8 million increase reflects the $2.5 million associated with the 2012 APCU (October Update and March Forecast) less the $0.7 million currently included in Oregon customers' rates related to the 2011 APCU.

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

A. Yes. Exhibit 205 provides a summary of the revenue change resulting from this year's combined October Update and March Forecast as compared to current revenue. The revenue amount shown on Exhibit 205 may differ slightly from the revenue requirement amounts shown on Exhibit 204 because of rounding and the rate design process. For example, Exhibit 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 204.

Q. Has the Company filed a tariff sheet that reflects the proposed change?

A. Yes. The Company is concurrently filing Advice No. 12-08 with this filing, which contains all of the effected tariffs, with an effective date of June 1, 2012.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott Wright

Mid Columbia Heavy and Light Load
Forward Market Prices

March 22, 2012

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	3/8/2012	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13
2	mc HL	16.85	16.50	14.70	23.25	27.50	26.45	24.75	27.95	31.75	29.50	29.50	29.50
3	mc LL	11.05	7.70	2.80	13.60	18.80	19.95	20.95	24.00	27.40	26.15	26.05	23.30
4	Reallocated Prices	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13
5	HL PP												
6	103.9%	17.51	17.14	15.27	24.16	28.57	27.48	25.72	29.04	32.99	30.65	30.65	30.65
7	LL PP												
8	107.1%	11.83	8.25	3.00	14.57	20.13	21.37	22.44	25.70	29.35	28.01	27.90	24.95
9	HL SS												
10	96.4%	16.24	15.91	14.17	22.41	26.51	25.50	23.86	26.94	30.61	28.44	28.44	28.44
11	LL SS												
12	93.4%	10.32	7.19	2.62	12.70	17.56	18.63	19.57	22.42	25.59	24.42	24.33	21.76

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott Wright

Idaho Power Company's Power Supply Costs
For April 1, 2012 through March 31, 2013

March 22, 2012

IPCO POWER SUPPLY COSTS FOR APRIL 1, 2012 – MARCH 31, 2013 (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)	956,285.0	1,043,411.8	951,143.0	772,234.6	526,755.2	443,525.0	480,657.8	403,236.0	625,600.4	683,144.4	848,873.5	884,677.2	8,619,543.9
Bridger													
Energy (MWh)	-	-	-	125,101.1	198,745.2	12,613.0	276,367.6	297,771.9	409,320.5	375,581.5	304,725.2	312,672.9	2,312,899.0
Cost ($ x 1000)	$ -	$ -	$ -	$ 3,313.7	$ 5,120.0	$ 338.7	$ 7,038.2	$ 7,547.7	$ 10,235.9	$ 8,500.8	$ 6,908.3	$ 7,128.6	$ 56,131.9
Boardman													
Energy (MWh)	4,765.2	-	1,664.8	37,974.2	39,271.7	36,226.4	35,610.3	34,060.4	37,063.1	28,754.9	26,248.5	30,613.5	312,253.1
Cost ($ x 1000)	$ 100.3	$ -	$ 33.6	$ 730.3	$ 751.7	$ 698.1	$ 691.2	$ 662.3	$ 715.2	$ 621.1	$ 565.9	$ 654.1	$ 6,223.7
Valmy													
Energy (MWh)	-	-	-	20,122.5	17,432.8	-	98,481.5	108,605.0	162,879.0	450.9	-	-	407,971.8
Cost ($ x 1000)	$ -	$ -	$ -	$ 660.7	$ 544.8	$ -	$ 3,089.0	$ 3,398.8	$ 5,002.6	$ 15.9	$ -	$ -	$ 12,712.0
Langley Gulch													
Energy (MWh)	-	-	-	142,287.0	148,565.3	141,370.1	160,708.9	130,288.7	127,730.1	26,258.4	3,735.9	2,360.0	883,304.3
Cost ($ x 1000)	$ -	$ -	$ -	$ 3,129.4	$ 3,287.8	$ 3,201.4	$ 3,747.5	$ 3,595.8	$ 4,265.4	$ 895.6	$ 124.3	$ 74.6	$ 22,321.9
Danskin													
Energy (MWh)	-	-	-	3,318.9	1,159.2	-	866.4	-	-	-	-	-	5,344.4
Cost ($ x 1000)	$ -	$ -	$ -	$ 111.2	$ 39.3	$ -	$ 31.0	$ -	$ -	$ -	$ -	$ -	$ 181.6
Fixed Capacity Charge - Gas Transportation ($ x 1000	$ 449.4	$ 421.7	$ 449.7	$ 435.9	$ 450.0	$ 445.2	$ 468.7	$ 468.7	$ 454.2	$ 450.0	$ 686.7	$ 709.0	$ 5,889.3
Total Cost	$ 449.4	$ 421.7	$ 449.7	$ 547.2	$ 489.3	$ 445.2	$ 499.8	$ 468.7	$ 454.2	$ 450.0	$ 686.7	$ 709.0	$ 6,070.9
Bennett Mountain													
Energy (MWh)	-	-	-	777.2	23.1	-	78.4	-	-	-	-	-	878.7
Cost ($ x 1000)	$ -	$ -	$ -	$ 26.4	$ 0.8	$ -	$ 2.8	$ -	$ -	$ -	$ -	$ -	$ 30.0
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	40,264.3	16,741.4	182,115.5	333,272.5	426,685.3	497,236.3	54,451.9	67,309.3	34,523.3	131,018.7	7,626.8	3,570.3	1,794,815.6
Contract Energy (MWh)	30,179.5	29,292.1	29,009.3	29,152.8	27,645.9	25,333.5	30,470.2	33,945.6	39,085.4	33,741.7	29,559.2	28,374.5	365,789.7
Total Energy Excl. CSPP (MWh)	70,443.9	46,033.5	211,124.8	362,425.3	454,331.2	522,569.8	84,922.1	101,254.9	73,608.7	164,760.5	37,186.0	31,944.8	2,160,605.3
Market Cost ($ x 1000)	$ 704.9	$ 286.7	$ 2,328.4	$ 7,397.9	$ 10,971.2	$ 12,981.9	$ 1,283.5	$ 1,807.5	$ 1,015.1	$ 3,826.1	$ 228.4	$ 109.4	$ 42,941.0
Contract Cost ($ x 1000)	$ 1,245.3	$ 1,210.8	$ 1,629.9	$ 1,965.1	$ 1,866.1	$ 1,425.1	$ 1,712.7	$ 2,287.8	$ 2,631.9	$ 1,948.1	$ 1,707.7	$ 1,206.5	$ 20,837.0
Total Cost Excl. CSPP ($ x 1000)	$ 1,950.2	$ 1,497.5	$ 3,958.3	$ 9,363.0	$ 12,837.3	$ 14,407.0	$ 2,996.2	$ 4,095.3	$ 3,647.0	$ 5,774.2	$ 1,936.1	$ 1,315.9	$ 63,778.1
Surplus Sales													
Energy (MWh)	124,450.9	83,091.4	5,482.3	9,326.0	1,986.7	767.0	131,480.5	90,504.4	180,197.9	10,749.6	267,642.8	328,770.1	1,234,449.4
Revenue Including Transmission Costs ($ x 1000)	$ 1,284.5	$ 662.9	$ 19.0	$ 120.2	$ 34.9	$ 14.3	$ 3,043.4	$ 2,383.1	$ 5,271.2	$ 283.1	$ 7,217.0	$ 8,440.1	$ 28,773.6
Transmission Costs ($ x 1000)	$ 124.5	$ 83.1	$ 5.5	$ 9.3	$ 2.0	$ 0.8	$ 131.5	$ 90.5	$ 180.2	$ 10.7	$ 267.6	$ 328.8	$ 1,234.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,160.1	$ 579.8	$ 13.5	$ 110.9	$ 32.9	$ 13.5	$ 2,911.9	$ 2,292.6	$ 5,091.0	$ 272.4	$ 6,949.4	$ 8,111.3	$ 27,539.2
Hoku First Block Revenues	$ 545.6	$ 545.6	$ 591.4	$ 637.2	$ 608.1	$ 563.2	$ 545.6	$ 545.6	$ 545.6	$ 545.6	$ 545.6	$ 545.6	$ 6,764.2
Net Hedges													
Energy (MWh)	(140,000.0)	(75,600.0)	7,600.0	49,200.0	7,800.0	(118,400.0)	(183,000.0)	(100,400.0)	(105,600.0)	(120,600.0)	(64,800.0)	(70,600.0)	(914,400.0)
Cost($ X 1000)	$ (4,956.0)	$ (3,100.4)	$ (1,085.6)	$ 1,335.3	$ 409.8	$ (4,327.9)	$ (6,328.5)	$ (3,293.2)	$ (4,488.0)	$ (4,159.3)	$ (2,209.2)	$ (2,405.0)	$ (34,608.0)
Net Power Supply Costs ($ x 1000)	$ (4,161.7)	$ (2,306.4)	$ 2,751.1	$ 18,357.9	$ 22,800.6	$ 14,185.8	$ 8,278.8	$ 13,637.2	$ 14,195.8	$ 11,280.4	$ 517.2	$ (1,179.6)	$\boxed{\$\ 98,357.0}$
PURPA ($ x 1000)	$ 14,067.2	$ 17,028.0	$ 19,882.5	$ 20,357.1	$ 18,666.5	$ 16,849.0	$ 15,803.8	$ 15,673.1	$ 16,687.8	$ 12,616.2	$ 12,661.5	$ 11,733.7	$ 192,026.2
Total Net Power Supply Expense ($ x 1000)	$ 9,905.4	$ 14,721.6	$ 22,633.5	$ 38,714.9	$ 41,467.1	$ 31,034.8	$ 24,082.6	$ 29,310.3	$ 30,883.6	$ 23,896.6	$ 13,178.7	$ 10,554.1	$\boxed{\$\ 290,383.2}$
Sales at Customer Level (In 000s MWH)	979.577	982.740	1,157.641	1,411.025	1,487.593	1,352.629	1,085.518	989.766	1,120.678	1,221.480	1,113.416	1,017.905	13,919.970
Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
Unit Cost / MWH (for PCAM)	$10.11	$14.98	$19.55	$27.44	$27.88	$22.94	$22.19	$29.61	$27.56	$19.56	$11.84	$10.37	$\boxed{\$20.86}$
Prices Used in Purchased Power & Surplus Sales Above:													
Heavy Load													
Portion of Purchased Power considered HL I	100.00%	99.80%	79.73%	79.57%	66.11%	77.54%	34.60%	34.44%	1.59%	45.24%	74.66%	100.00%	
Purchased Power HL Price	17.51	17.14	15.27	24.16	28.57	27.48	25.72	29.04	32.99	30.65	30.65	30.65	
Portion of Surplus Sales considered HL Surp	0.02%	9.01%	7.31%	1.90%	0.00%	0.00%	83.42%	86.46%	72.98%	47.67%	64.14%	58.56%	
Surplus Sales HL Price	16.24	15.91	14.17	22.41	26.51	25.50	23.86	26.94	30.61	28.44	28.44	28.44	
Light Load													
Portion of Purchased Power considered LL F	0.00%	0.20%	20.27%	20.43%	33.89%	22.46%	65.40%	65.56%	98.41%	54.76%	25.34%	0.00%	
Purchased Power LL Price	11.83	8.25	3.00	14.57	20.13	21.37	22.44	25.70	29.35	28.01	27.90	24.95	
Portion of Surplus Sales considered LL Surp	99.98%	90.99%	92.69%	98.10%	100.00%	100.00%	16.58%	13.54%	27.02%	52.33%	35.86%	41.44%	
Surplus Sales LL Price	10.32	7.19	2.62	12.70	17.56	18.63	19.57	22.42	25.59	24.42	24.33	21.76	

Idaho Power/203
Witness: Scott Wright

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott Wright

Idaho Power Company's Combined Rate Calculation

March 22, 2012

ANNUAL POWER COST UPDATE
April 2012 - March 2013

Line		
	OCTOBER APCU	
1	Forecast of Normalized Sales (MWh)	14,713,937
2	Total Net Power Supply Expense	$279,231,558
3	October APCU Rate ($/MWh)	$18.98
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	13,919,970
5	Total Net Power Supply Expense	$290,383,239
6	March Forecast Rate ($/MWh)	$20.86
7	Sales Adjusted Forecast Power Cost Change	$26,219,072
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$24,908,118
10	**March Forecast Rate Adjustment ($/MWh)**	$1.79
11	**Combined Rate ($/MWh)**	$20.77

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott Wright

Idaho Power Company's Revenue Spread
for the October Update and March Forecast

March 22, 2012

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: 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	2012 October Update APCU Cost of Service (Allocator -- Line 14)	$1,298,993	$427,230	$35,118	$223,454	$28,138	$5,025	$722	$310,094	$150,288	$117,706	$24	$1,163	$30
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	3.12%	2.63%	2.19%	3.12%	3.43%	3.24%	0.64%	3.67%	4.50%	3.19%	2.35%	0.91%	2.30%
44	Proposed Combined Revenue Spread (Line 36 + Line 42)	$42,983,473	$16,645,510	$1,638,671	$7,396,885	$848,838	$160,022	$113,184	$8,755,704	$3,486,458	$3,807,295	$1,040	$128,521	$1,345
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	2012 October Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 42/Line 45))	1.998	2.149	1.968	1.956	1.864	1.774	1.492	1.731	2.027	2.523	1.850	1.495	1.852
47	APCU Incremental Rate for 2012 October Update (Mills per kWh) (Line 46*(Column A:[Line 45/Line 48]))	**2.020**	**2.234**	**1.946**	**1.983**	**1.920**	**1.799**	**1.502**	**1.845**	**1.964**	**2.036**	**1.850**	**1.491**	**1.851**
48	*Loss-Adjusted 2012-2013 Normolized Sales (kWh)*	643,065,633	191,221,945	18,043,183	112,672,964	14,653,734	2,793,636	480,698	168,063,365	76,507,917	57,818,841	12,900	780,105	16,345
49	Projected October Update APCU 2012-2013 Revenues (Line 47 * Line 48)	$1,298,993	$427,230	$35,118	$223,454	$28,138	$5,025	$722	$310,094	$150,288	$117,706	$24	$1,163	$30

Notes:

1 **2012 October Update APCU Revenues = $2.02/MWh x 643,065.633 MW's = $ 1,298,993** (Line 42, Column A)

2 **$2.02 = $18.98 (2012 October APCU Rate) - $16.96 (2011 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													

2012 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	2012 March Forecast APCU Cost of Service (Allocator -- Line 14)	$1,151,087	$378,585	$31,120	$198,011	$24,934	$4,453	$640	$274,786	$133,176	$104,304	$21	$1,031	$27
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	2.76%	2.33%	1.94%	2.76%	3.04%	2.87%	0.57%	3.25%	3.99%	2.83%	2.08%	0.81%	2.04%
44	Proposed Combined Revenue Spread (Line 36 + Line 42)	$42,835,568	$16,596,865	$1,634,673	$7,371,442	$845,634	$159,450	$113,102	$8,720,397	$3,469,346	$3,793,892	$1,037	$128,388	$1,342
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	2012 March Forecast Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 42/Line 45))	1.770	1.904	1.744	1.733	1.651	1.572	1.322	1.534	1.796	2.236	1.639	1.324	1.642
47	**APCU Incremental Rate for 2012 March Forecast (Mills per kWh) (Line 46*(Column A:[Line 45/Line 48]))**	**1.790**	**1.980**	**1.725**	**1.757**	**1.702**	**1.594**	**1.331**	**1.635**	**1.741**	**1.804**	**1.639**	**1.321**	**1.640**
48	*Loss-Adjusted 2012-2013 Normalized Sales (kWh)*	643,065,633	191,221,945	18,043,183	112,672,964	14,653,734	2,793,636	480,698	168,063,365	76,507,917	57,818,841	12,900	780,105	16,345
49	Projected March Forecast APCU 2012-2013 Revenues (Line 47 * Line 48)	$1,151,088	$378,585	$31,120	$198,011	$24,934	$4,453	$640	$274,786	$133,176	$104,304	$21	$1,031	$27

Notes:

1 2012 March Forecast APCU Revenues = $1.79/MWh x 643,065.633 MW's = $ 1,151,087 (Line 42, Column A)

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott Wright

Summary of Revenue Impact

March 22, 2012

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2012

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (1) (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	191,221,945	$16,490,321	86.24	$620,330	$17,110,651	89.48	3.76%
2	Small General Service	7	2,481	18,043,183	$1,700,666	94.26	$48,592	$1,749,258	96.95	2.86%
3	Large General Service	9	898	130,120,335	$8,601,109	66.10	$358,201	$8,959,310	68.85	4.16%
4	Dusk to Dawn Lighting	15	0	480,698	$113,150	235.39	$1,362	$114,512	238.22	1.20%
5	Large Power Service	19	7	244,571,282	$12,490,226	51.07	$648,082	$13,138,308	53.72	5.19%
6	Agricultural Irrigation Service	24	1,566	57,818,841	$4,794,051	82.92	$115,103	$4,909,154	84.91	2.40%
7	Unmetered General Service	40	3	12,900	$1,072	83.10	$33	$1,105	85.68	3.10%
8	Street Lighting	41	14	780,105	$130,792	167.66	$1,581	$132,373	169.69	1.21%
9	Traffic Control Lighting	42	7	16,345	$1,397	85.49	$33	$1,430	87.52	2.37%
10	Total Uniform Tariffs		18,424	643,065,634	$44,322,783	68.92	$1,793,317	$46,116,101	71.71	4.05%
12	Total Oregon Retail Sales		18,424	643,065,634	$44,322,783	68.92	$1,793,317	$46,116,101	71.71	4.05%

(1) Updated April 2012-March 2013 Test Year

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket UE 242 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.

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DATED: March 22, 2012

Wendy McIndoo

Wendy McIndoo
Office Manager