

McDowell Rackner & Gibson PC



WENDY MCINDOO
Direct (503) 595-3922
wendy@mcd-law.com

March 23, 2011

VIA ELECTRONIC AND U.S. MAIL

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

Re: UE 222 - In The Matter of IDAHO POWER COMPANY's 2011 Annual Power Cost Update

Attention Filing Center:

Enclosed for filing in the above-referenced docket are an original and five copies of Idaho Power'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 me with any questions.

Very truly yours,

A handwritten signature in cursive script that reads "Wendy McIndoo".

Wendy McIndoo
Legal Assistant

Enclosures
cc: Service List

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in
UE 222 on the following named person(s) on the date indicated below by email and first-
class mail addressed to said person(s) at his or her last-known address(es) indicated below.

| | |
|---|---|
| Ed Durrenberger Public Utility Commission of Oregon ed.durrenberger@state.or.us | Robert Jenks Citizens' Utility Board of Oregon bob@oregoncub.org |
| Gordon Feighner Citizens' Utility Board of Oregon gordon@oregoncub.org | Catriona McCracken Citizens' Utility Board of Oregon catriona@oregoncub.org |
| Stephanie S. Andrus Department Of Justice Assistant Attorney General Business Activities Section stephanie.andrus@state.or.us | |

DATED: March 23, 2011



Wendy McIndoo
Legal Assistant

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 222

IN THE MATTER OF IDAHO POWER)
COMPANY'S 2011 ANNUAL POWER)
COST UPDATE)
MARCH FORECAST)
_____)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

SCOTT WRIGHT

March 23, 2011

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

3 A. Yes. I previously submitted testimony in this proceeding regarding the
4 October Update for the 2011 Annual Power Cost Update ("APCU"). The October Update is
5 the Company's estimate of what "normalized" power supply expenses will be for the
6 upcoming year.

7 **Q. What is the purpose of your testimony?**

8 A. The purpose of my testimony is to describe Idaho Power Company's ("Idaho
9 Power" or "Company") March Forecast for the 2011 APCU which is required as detailed in
10 Order No. 08-238.

11 **Q. What is the March Forecast?**

12 A. The March Forecast is the Company's estimate of the "expected" net power
13 supply expense for an upcoming water year using the AURORA model. In this case, the
14 water year is April 2011 through March 2012.

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

17 A. The following variables are delineated in Order No. 08-238 and are to be
18 updated in the March Forecast:

- 19 a. Fuel prices and transportation costs;
- 20 b. Wheeling expenses;
- 21 c. Planned outages and forced outage rates;
- 22 d. Heat rates;
- 23 e. Forecast of normalized sales and loads, updated only for known
24 significant changes since the October APCU filing.

25

26

- 1 f. Forecast hydro generation from stream flow conditions using the most
2 recent water supply forecast from the Northwest River Forecast Center in Portland,
3 Oregon, and current reservoir levels;
- 4 g. Contracts for wholesale power and power purchases and sales;
- 5 h. Forward price curve as defined below;
- 6 i. PURPA contract expenses; and
- 7 j. The Oregon state allocation factor.

8 **Q. Which of the above variables were updated for the March Forecast?**

9 A. All of the above variables were reviewed for the March Forecast; however, for
10 the April 2011 through March 2012 test period the only variables that have changed from the
11 October Update APCU are: (1) fuel prices; (2) the forecast of normalized sales and loads;
12 (3) the forecast of hydro conditions from the Northwest River Forecast Center; (4) known
13 power purchases and surplus sales resulting from the Company's Risk Management Policy;
14 and (5) the forward price curve in accordance with Order No. 08-238.

15 **Q. What fuel prices were changed?**

16 A. The coal price forecast and the natural gas price forecast used in the October
17 Update were replaced with updated forecasts in accordance with Order No. 08-238 as
18 described above.

19 **Q. How have the coal costs and natural gas price changed as compared to**
20 **those included in the October Update?**

21 A. The coal costs used in the March Forecast are slightly higher, while the
22 natural gas price is lower than that used in the October Update. The coal cost for Bridger
23 increased on a \$/megawatt-hours ("MWh") by less than 1 percent from the October Update,
24 the coal cost for Valmy increased on a \$/MWh by 10 percent from the October Update, the
25 coal cost for Boardman increased on a \$/MWh by 1 percent from the October Update, and
26 the natural gas price decreased by 15 percent from the October Update.

1 **Q. What is the reason for the increase in the coal costs since the October**
2 **Update was filed?**

3 A. As mentioned above, the increase in the coal costs at the Bridger and
4 Boardman plants have not changed materially from the October Update. The per unit cost
5 of production at the Valmy plant increased as a result of expected decreased generation at
6 the plant. That is, the fixed portion of the Oil, Administrative & General, and Handling costs
7 are spread over fewer units of production, resulting in a higher cost per unit.

8 **Q. Please explain why the forecast of normalized sales and loads were**
9 **updated from the October Update.**

10 A. Since the October Update was filed, an updated forecast of normalized sales
11 and loads was created. The updated forecast includes a revised ramp up schedule for
12 special contract customer Hoku Materials, Inc. The sales and load used for the March
13 Forecast forecasted 1,798 average megawatts ("aMW"), 28 aMW lower than the forecast
14 used in the October Update of 1,826 aMW. The majority of the decrease in the forecast is
15 the result of the revised ramp up schedule for Hoku Materials, Inc.

16 **Q. What water supply forecast from the Northwest River Forecast Center**
17 **was used to create the hydro generation forecast for the March Forecast?**

18 A. The forecasted monthly hydro generation levels included in the March
19 Forecast reflect the Northwest River Forecast Center's March 7, 2011, Final Streamflow
20 Forecast and current reservoir levels. The March 7th Final Streamflow Forecast has
21 expected inflows into Brownlee Reservoir for April through July of 5.7 million acre-feet
22 ("MAF"), or 90 percent of the 30-year average level of 6.31 MAF.

23 **Q. How does the March 7, 2011, Northwest River Forecast Center's**
24 **forecast compare to last year's March 5, 2010, Northwest River Forecast Center's**
25 **forecast?**

26

1 A. The forecast for last year's March forecast was 2.47 MAF or 39 percent of
2 average. While last year's forecast was for below average streamflows, this year's forecast
3 is closer to average hydro conditions. The stream flow forecast for this year is significantly
4 higher than last year's forecast by 3.23 MAF (5.7 MAF – 2.47 MAF = 3.23 MAF).

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

7 A. Exhibit No. 201 shows the March 10, 2011, mid-Columbia price curve for the
8 April 2011 through March 2012 test period the Company used pursuant to Order No. 08-
9 238.

10 **Q. Has the Company adhered to the Stipulation in UM 1355, Order No. 10-**
11 **414, for forecasting its equivalent forced outage rate ("EFOR")?**

12 A. Yes. The Company has adhered to the stipulation approved in Order No. 10-
13 414 for calculating its EFOR. The Company's EFOR also falls within the North American
14 Electric Reliability Corporation ("NERC") guidelines for excluding extreme events for coal
15 units as outlined in Order No. 10-414.

16 **Q. Were there any other items in the Stipulation approved in Order No. 10-**
17 **414 that the Company needed to address?**

18 A. Yes. The Company agreed to investigate the shifting of designated EFOR
19 hours from Heavy Load Hours ("HLH") to Light Load Hours ("LLH") within the AURORA
20 model. The Company prepared an analysis that modeled the changes that occur when
21 EFOR hours are shifted from HLH to LLH. The analysis confirmed that the Company's
22 traditional methodology of modeling EFOR hours on an annual basis would not be materially
23 enhanced or improved by moving to a HLH/LLH methodology. The results were presented
24 to Commission Staff, along with a recommendation to continue using the traditional
25 methodology for modeling EFOR hours. Commission Staff is currently reviewing the
26

1 Company's analysis. The March Forecast net power supply expense run uses the
2 Company's traditional methodology.

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

8 A. Exhibit No. 202 shows the results of a single water condition for the April
9 2011 through March 2012 test period, with updated fuel prices, updated normalized sales
10 and loads, updated stream flow conditions and reservoir levels, updated power purchases
11 and surplus sales from the Company's Risk Management Policy (Net Hedges), and market
12 purchased power and surplus sales repriced pursuant to Order No. 08-238. The March
13 Forecast for net power supply expense without PURPA is \$130.4 million. When you include
14 the PURPA expense of \$129.1 million, the total net power supply expense for the March
15 Forecast is \$259.5 million

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

18 A. Exhibit No. 202 shows the normalized annual sales at the customer level for
19 the April 2011 through March 2012 test period is 14,389,811 MWh. Based upon test period
20 sales, the cost per unit for the March Forecast to become effective on June 1, 2011, is
21 \$18.03 per MWh (\$259.5 million / 14.389 million MWh = \$18.03 per MWh).

22 **Q. How does this \$18.03 per MWh March Forecast compare to the March**
23 **Forecast that resulted from last year's computation?**

24 A. The March Forecast for last year's April 2010 through March 2011 test period
25 was \$19.93 per MWh, as compared to this year's April 2011 through March 2012 test period
26 of \$18.03 per MWh.

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

3 A. Exhibit No. 203 steps through the Commission specified method of
4 calculating the March Forecast rate, pursuant to Order No. 08-238. Lines 1-3 show the
5 calculation for the October APCU rate of \$16.96 per MWh. Lines 4-6 show the calculation
6 for the March Forecast rate of \$18.03 per MWh. Line 7 is calculated by subtracting the
7 March Forecast rate from the October APCU rate multiplied by the March Forecast of
8 Normalized Sales, line 6 minus line 3 multiplied by line 4. Line 8 is the allocated amount (95
9 percent) that is allowed for the March Forecast rate. Line 9, the Forecast Change Allowed,
10 is calculated by multiplying line 7 by line 8. Line 10 is calculated by dividing line 9 by line 4
11 to create the March Forecast Rate Adjustment.

12 **Q. Please explain how the revenue requirement for the March Forecast is**
13 **calculated using the March Forecast Rate Adjustment unit cost of \$1.02 per MWh.**

14 A. The revenue requirement for the March Forecast is calculated by multiplying
15 the unit cost of \$1.02 per MWh by the sales for the April 2011 through March 2012 test
16 period of 651,435.404 MWh creating a revenue requirement of \$664,464.

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

19 A. Idaho Power proposes to allocate the revenue requirement associated with
20 the 2011 March Forecast according to the revenue spread methodology approved by the
21 Commission in UE 214, Order No. 10-191. Order No. 10-191 established a revenue spread
22 methodology whereby the revenue requirement for the March Forecast is allocated to
23 individual customer classes on the basis of the total generation-related revenue requirement
24 approved in the Company's last general rate case, UE 213, plus last year's October Update,
25 UE 214, as well as this year's proposed October Update. The Commission's preferred
26 allocation methodology further applies a subsidy correction adjustment to any customer

1 class whose final revenue allocation in UE 213 was below the cost of service revenue
2 requirement. As a result of applying the subsidy correction adjustment in this case, Irrigation
3 Service and Traffic Control Lighting Service receive a revenue increase equal to 150
4 percent of the 2011 March Forecast cost of service revenue requirement. The proposed
5 revenue spread resulting from the application of the Commission-approved allocation
6 methodology is shown on Exhibit No. 204. Exhibit No. 204 also shows the revised revenue
7 spread for the October Update.

8 **Q. Why did the Company revise the revenue spread for the October**
9 **Update?**

10 A. The Company revised the revenue spread for the October Update to reflect
11 the new sales that were used for the March Forecast filing. The sales used for the October
12 Update were 26,462.457 MWh higher than the sales used for the March Forecast filing
13 (26,462.457 MWh = October Update 677,897.861 MWh – March Forecast 651,435.404
14 MWh). The change in sales reduces the Oregon jurisdictional allocation of the October
15 Update revenue requirement by \$100,206.

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

19 A. The overall revenue impact of this year's combined October Update and
20 March Forecast is a 2.17 percent average overall decrease from last year's combined
21 October Update and March Forecast.

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

25 A. Yes. Exhibit No. 205 provides a summary of the revenue change resulting
26 from this year's combined October Update and March Forecast as compared to current

1 revenue. The revenue amount shown on Exhibit No. 205 may differ slightly from the
2 revenue requirement amounts shown on Exhibit No. 204 because of rounding and the rate
3 design process. For example, Exhibit No. 204 shows a cents per kilowatt-hour ("kWh) for
4 Schedule 41 – Municipal Street Lights. However, in the rate design process, this amount is
5 converted to a cents per lamp charge. The end result is a slight difference from the revenue
6 requirement amount shown on Exhibit No. 204.

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

8 A. Yes. The Company is concurrently filing Advice No. 11-05 with this filing,
9 which contains all of the affected tariffs, with an effective date of June 1, 2011.

10 **Q. Does this conclude your testimony?**

11 A. Yes it does.

12

13

14

15

16

17

18

19

20

21

22

23

24

25

26

Idaho Power/201
Witness: Scott Wright

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 222
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

March 10, 2010, Mid-Columbia Price Curve – April 2011 – March 2011

March 23, 2011

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

| Mid-Columbia Forward | | | | | | | | | | | | | |
|-----------------------------|---------------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| <u>Line</u> | Price Curve on: | | | | | | | | | | | | |
| 1 | 3/10/2011 | Apr-11 | May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 |
| 2 | mc HL | 22.00 | 15.80 | 14.05 | 28.65 | 37.10 | 35.40 | 34.60 | 36.10 | 40.20 | 40.15 | 38.45 | 33.85 |
| 3 | mc LL | 14.30 | 7.90 | 5.25 | 16.85 | 26.85 | 27.15 | 28.90 | 31.10 | 34.70 | 35.35 | 32.72 | 30.04 |
| 4 | Reallocated Prices | Apr-11 | May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 |
| 5 | HL PP | | | | | | | | | | | | |
| 6 | 103.9% | 22.86 | 16.42 | 14.60 | 29.77 | 38.55 | 36.78 | 35.95 | 37.51 | 41.77 | 41.72 | 39.95 | 35.17 |
| 7 | LL PP | | | | | | | | | | | | |
| 8 | 107.1% | 15.32 | 8.46 | 5.62 | 18.05 | 28.76 | 29.08 | 30.95 | 33.31 | 37.16 | 37.86 | 35.04 | 32.17 |
| 9 | HL SS | | | | | | | | | | | | |
| 10 | 96.4% | 21.21 | 15.23 | 13.54 | 27.62 | 35.76 | 34.13 | 33.35 | 34.80 | 38.75 | 38.70 | 37.07 | 32.63 |
| 11 | LL SS | | | | | | | | | | | | |
| 12 | 93.4% | 13.36 | 7.38 | 4.90 | 15.74 | 25.08 | 25.36 | 26.99 | 29.05 | 32.41 | 33.02 | 30.56 | 28.06 |

Idaho Power/202
Witness: Scott Wright

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 222
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright
Power Supply Costs for April 1, 2011 – March 31, 2011

March 23, 2011

IPCO POWER SUPPLY COSTS FOR APRIL 1, 2011 -- MARCH 31, 2012 (One Hydro Condition)
Repriced Using UE195 Settlement Methodology - March Forecast

| | <u>April</u> | <u>May</u> | <u>June</u> | <u>July</u> | <u>August</u> | <u>September</u> | <u>October</u> | <u>November</u> | <u>December</u> | <u>January</u> | <u>February</u> | <u>March</u> | <u>Annual</u> |
|--|--------------|-------------|-------------|-------------|---------------|------------------|----------------|-----------------|-----------------|----------------|-----------------|--------------|---------------|
| Hydroelectric Generation (MWh) | 1,168,181.0 | 1,014,284.2 | 898,295.0 | 709,143.4 | 589,251.2 | 423,869.0 | 502,977.8 | 409,212.0 | 682,814.0 | 715,285.2 | 949,208.0 | 861,613.2 | 8,924,134.0 |
| Bridger | | | | | | | | | | | | | |
| Energy (MWh) | 119,342.9 | 89,978.4 | 63,257.7 | 362,349.0 | 411,588.1 | 384,781.2 | 428,928.9 | 438,735.5 | 475,706.2 | 377,596.6 | 339,803.8 | 192,842.8 | 3,684,911.2 |
| Cost (\$ x 1000) | \$ 2,726.7 | \$ 2,051.8 | \$ 1,462.3 | \$ 8,156.6 | \$ 9,219.9 | \$ 8,619.9 | \$ 9,570.6 | \$ 9,740.0 | \$ 10,516.6 | \$ 8,550.5 | \$ 7,705.3 | \$ 4,451.9 | \$ 82,772.0 |
| Boardman | | | | | | | | | | | | | |
| Energy (MWh) | 13,018.7 | 1,616.3 | 21,818.0 | 37,828.8 | 37,399.8 | 35,796.5 | 34,752.5 | 33,791.8 | 36,968.3 | 28,623.5 | 27,582.8 | 29,253.6 | 338,450.5 |
| Cost (\$ x 1000) | \$ 247.3 | \$ 31.1 | \$ 415.4 | \$ 681.7 | \$ 674.9 | \$ 647.0 | \$ 633.6 | \$ 615.7 | \$ 668.2 | \$ 596.0 | \$ 571.5 | \$ 606.9 | \$ 6,389.2 |
| Valmy | | | | | | | | | | | | | |
| Energy (MWh) | - | - | - | 103,367.6 | 146,034.6 | 115,510.9 | 158,077.7 | 158,666.1 | 169,468.6 | 146,766.3 | 124,438.9 | 872.5 | 1,123,203.1 |
| Cost (\$ x 1000) | \$ - | \$ - | \$ - | \$ 3,285.6 | \$ 4,515.7 | \$ 3,589.6 | \$ 4,871.0 | \$ 4,875.3 | \$ 5,186.5 | \$ 4,485.0 | \$ 3,812.7 | \$ 30.8 | \$ 34,652.1 |
| Danskin | | | | | | | | | | | | | |
| Energy (MWh) | - | - | - | - | 325.9 | 1,835.2 | - | - | - | - | - | - | 2,161.1 |
| Cost (\$ x 1000) | \$ - | \$ - | \$ - | \$ - | \$ 14.5 | \$ 81.1 | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - | \$ 95.6 |
| Fixed Capacity Charge - Gas Transportation (\$ x 1000) | \$ 220.8 | \$ 220.8 | \$ 241.2 | \$ 234.4 | \$ 241.2 | \$ 234.4 | \$ 241.2 | \$ 241.2 | \$ 234.4 | \$ 241.2 | \$ 234.4 | \$ 241.2 | \$ 2,826.5 |
| Total Cost | \$ 220.8 | \$ 220.8 | \$ 241.2 | \$ 234.4 | \$ 255.8 | \$ 315.5 | \$ 241.2 | \$ 241.2 | \$ 234.4 | \$ 241.2 | \$ 234.4 | \$ 241.2 | \$ 2,922.2 |
| Bennett Mountain | | | | | | | | | | | | | |
| Energy (MWh) | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Cost (\$ x 1000) | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Purchased Power (Excluding CSPP) | | | | | | | | | | | | | |
| Market Energy (MWh) | 17,495.8 | 42,046.0 | 111,706.8 | 78,189.9 | 61,065.2 | 189,793.8 | 15,850.2 | 32,587.6 | 1,862.9 | 58,100.2 | 2,417.5 | 123,646.7 | 734,762.6 |
| Contract Energy (MWh) | 27,086.1 | 30,806.6 | 63,919.2 | 66,356.3 | 62,557.4 | 22,010.0 | 31,184.2 | 29,743.0 | 36,917.3 | 30,054.1 | 25,920.7 | 25,715.8 | 452,270.8 |
| Total Energy Excl. CSPP (MWh) | 44,581.9 | 72,852.6 | 175,625.9 | 144,546.2 | 123,622.7 | 211,803.7 | 47,034.4 | 62,330.6 | 38,780.2 | 88,154.3 | 28,338.2 | 149,362.6 | 1,187,033.3 |
| Market Cost (\$ x 1000) | \$ 379.8 | \$ 653.5 | \$ 1,291.2 | \$ 2,095.9 | \$ 2,036.9 | \$ 6,634.4 | \$ 496.2 | \$ 1,125.6 | \$ 69.2 | \$ 2,260.4 | \$ 94.3 | \$ 4,243.6 | \$ 21,381.0 |
| Contract Cost (\$ x 1000) | \$ 1,092.0 | \$ 1,240.8 | \$ 4,746.9 | \$ 5,236.4 | \$ 5,029.8 | \$ 1,212.0 | \$ 1,708.9 | \$ 1,956.8 | \$ 2,423.3 | \$ 1,685.0 | \$ 1,456.6 | \$ 1,065.1 | \$ 28,853.6 |
| Total Cost Excl. CSPP (\$ x 1000) | \$ 1,471.9 | \$ 1,894.3 | \$ 6,038.1 | \$ 7,332.4 | \$ 7,066.7 | \$ 7,846.4 | \$ 2,205.1 | \$ 3,082.4 | \$ 2,492.5 | \$ 3,945.3 | \$ 1,550.9 | \$ 5,308.6 | \$ 50,234.6 |
| Surplus Sales | | | | | | | | | | | | | |
| Energy (MWh) | 288,318.3 | 72,089.5 | 42,172.8 | 41,256.5 | 73,817.0 | 14,691.0 | 102,289.3 | 31,145.0 | 156,866.3 | 98,312.5 | 332,461.8 | 46,182.7 | 1,299,602.8 |
| Revenue Including Transmission Costs (\$ x 1000) | \$ 4,760.7 | \$ 824.5 | \$ 433.6 | \$ 867.6 | \$ 2,377.1 | \$ 406.2 | \$ 3,241.6 | \$ 1,020.8 | \$ 5,796.5 | \$ 3,669.7 | \$ 11,367.2 | \$ 1,418.1 | \$ 36,183.6 |
| Transmission Costs (\$ x 1000) | \$ 288.3 | \$ 72.1 | \$ 42.2 | \$ 41.3 | \$ 73.8 | \$ 14.7 | \$ 102.3 | \$ 31.1 | \$ 156.9 | \$ 98.3 | \$ 332.5 | \$ 46.2 | \$ 1,299.6 |
| Revenue Excluding Transmission Costs (\$ x 1000) | \$ 4,472.3 | \$ 752.4 | \$ 391.4 | \$ 826.4 | \$ 2,303.3 | \$ 391.5 | \$ 3,139.3 | \$ 989.6 | \$ 5,639.6 | \$ 3,571.4 | \$ 11,034.8 | \$ 1,371.9 | \$ 34,884.0 |
| Hoku First Block Revenues | \$ 1,638.2 | \$ 1,692.8 | \$ 1,178.7 | \$ 743.2 | \$ 1,073.5 | \$ 1,977.8 | \$ 2,353.4 | \$ 2,280.6 | \$ 2,353.4 | \$ 2,353.4 | \$ 2,201.6 | \$ 2,350.2 | \$ 22,196.7 |
| Net Hedges | | | | | | | | | | | | | |
| Energy (MWh) | (171,200.0) | (20,800.0) | 92,000.0 | 264,856.0 | 202,800.0 | - | (78,200.0) | (15,200.0) | 34,200.0 | 24,600.0 | (70,000.0) | (140,400.0) | 122,656.0 |
| Cost (\$ x 1000) | \$ (4,609.0) | \$ (455.5) | \$ 969.4 | \$ 11,047.3 | \$ 11,292.2 | \$ 1,466.5 | \$ (2,595.8) | \$ (513.0) | \$ 1,285.5 | \$ 934.9 | \$ (2,917.6) | \$ (5,339.4) | \$ 10,565.4 |
| Net Power Supply Costs (\$ x 1000) | \$ (6,052.9) | \$ 1,297.3 | \$ 7,556.4 | \$ 29,168.4 | \$ 29,648.4 | \$ 20,115.6 | \$ 9,432.9 | \$ 14,771.3 | \$ 12,390.7 | \$ 12,828.2 | \$ (2,279.2) | \$ 1,577.9 | \$ 130,454.9 |
| PURPA (\$ x 1000) | \$ 9,644.1 | \$ 12,167.0 | \$ 13,993.0 | \$ 14,311.8 | \$ 13,378.7 | \$ 11,978.7 | \$ 10,140.6 | \$ 9,123.2 | \$ 9,393.8 | \$ 8,333.2 | \$ 8,387.4 | \$ 8,199.6 | \$ 129,051.2 |
| Total Net Power Supply Expense (\$ x 1000) | \$ 3,591.2 | \$ 13,464.3 | \$ 21,549.4 | \$ 43,480.3 | \$ 43,027.0 | \$ 32,094.3 | \$ 19,573.5 | \$ 23,894.5 | \$ 21,784.5 | \$ 21,161.4 | \$ 6,108.2 | \$ 9,777.5 | \$ 259,506.2 |
| Sales at Customer Level (in 000s MWh) | 987.169 | 985.401 | 1,169.719 | 1,429.673 | 1,495.497 | 1,393.211 | 1,124.675 | 1,042.504 | 1,176.700 | 1,287.009 | 1,200.626 | 1,097.626 | 14,389.811 |
| Hours in Month | 720 | 744 | 720 | 744 | 744 | 720 | 744 | 720 | 744 | 744 | 696 | 744 | 8784 |
| Unit Cost / MWh (for PCAM) | \$3.64 | \$13.66 | \$18.42 | \$30.41 | \$28.77 | \$23.04 | \$17.40 | \$22.92 | \$18.51 | \$16.44 | \$5.09 | \$8.91 | \$18.03 |
| Prices Used in Purchased Power & Surplus Sales Above: | | | | | | | | | | | | | |
| Heavy Load | | | | | | | | | | | | | |
| Portion of Purchased Power considered HL F | 84.79% | 89.02% | 66.14% | 74.73% | 46.98% | 76.31% | 7.04% | 29.38% | 0.00% | 27.13% | 80.62% | 71.63% | |
| Purchased Power HL Price | 22.86 | 16.42 | 14.60 | 29.77 | 38.55 | 36.78 | 35.95 | 37.51 | 41.77 | 41.72 | 39.95 | 35.17 | |
| Portion of Surplus Sales considered HL Surp | 40.19% | 51.68% | 62.24% | 44.55% | 66.67% | 26.15% | 73.85% | 64.78% | 71.60% | 75.78% | 55.82% | 57.91% | |
| Surplus Sales HL Price | 21.21 | 15.23 | 13.54 | 27.62 | 35.76 | 34.13 | 33.35 | 34.80 | 38.75 | 38.70 | 37.07 | 32.63 | |
| Light Load | | | | | | | | | | | | | |
| Portion of Purchased Power considered LL F | 15.21% | 10.98% | 33.86% | 25.27% | 53.02% | 23.69% | 92.96% | 70.62% | 100.00% | 72.87% | 19.38% | 28.37% | |
| Purchased Power LL Price | 15.32 | 8.46 | 5.62 | 18.05 | 28.76 | 29.08 | 30.95 | 33.31 | 37.16 | 37.86 | 35.04 | 32.17 | |
| Portion of Surplus Sales considered LL Surp | 59.81% | 48.32% | 37.76% | 55.45% | 33.33% | 73.85% | 26.15% | 35.22% | 28.40% | 24.22% | 44.18% | 42.09% | |
| Surplus Sales LL Price | 13.36 | 7.38 | 4.90 | 15.74 | 25.08 | 25.36 | 26.99 | 29.05 | 32.41 | 33.02 | 30.56 | 28.06 | |

Idaho Power/203
Witness: Scott Wright

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 222
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright
Annual Power Cost Update – April 2011 – March 2012

March 23, 2011

ANNUAL POWER COST UPDATE
April 2011 - March 2012

| | | |
|-------------|---|----------------------|
| <u>Line</u> | <u>OCTOBER APCU</u> | |
| 1 | Forecast of Normalized Sales (MWh) | 14,590,974 |
| 2 | Total Net Power Supply Expense | <u>\$247,467,046</u> |
| 3 | October APCU Rate (\$/MWh) | \$16.96 |
| | | |
| | <u>MARCH FORECAST</u> | |
| 4 | Forecast of Normalized Sales (MWh) | 14,389,811 |
| 5 | Total Net Power Supply Expense | <u>\$259,506,170</u> |
| 6 | March Forecast Rate (\$/MWh) | \$18.03 |
| | | |
| 7 | Sales Adjusted Forecast Power Cost Change | \$15,450,905 |
| 8 | Portion of Change Allowed | <u>95%</u> |
| 9 | Forecast Change Allowed | \$14,678,360 |
| | | |
| 10 | March Forecast Rate Adjustment (\$/MWh) | \$1.02 |
| | | |
| 11 | <u>Combined Rate (\$/MWh)</u> | <u>\$17.98</u> |

Idaho Power/204
Witness: Scott Wright

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 222
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright
Rate Spread for October Update and March Forecast

March 23, 2011

IDAHO POWER COMPANY
Rate Spread Exhibit for October Update APCU

| General Rate Case (UE 213): Marginal Cost-of-Service Study and Stipulated Revenue Spread | | | | | | | | | | | | | |
|--|---|--------------------------------|---------------------------|-----------------------|--------------------------------------|------------------------------------|---------------------------------|--------------------------------------|------------------------------------|--|---|--------------------------------------|-----------------------------------|
| 2009 Test Period | | | | | | | | | | | | | |
| Line | Description | (A) TOTAL SYSTEM/AVERAGE | (B) RESIDENTIAL (1) | (C) GEN SRV (7) | (D) GEN SRV SECONDARY (9-S) | (E) GEN SRV PRIMARY (9-P) | (F) AREA LIGHTING (15) | (G) LG POWER PRIMARY (19-P) | (H) LG POWER TRANS (19-T) | (I) IRRIGATION SECONDARY (24-S) | (J) UNMETERED GEN SERVICE (40) | (K) MUNICIPAL ST LIGHT (41) | (L) TRAFFIC CONTROL (42) |
| 1 | <u>Loss-Inflated Normalized Sales (kWh)</u> | 740,533,031 | 220,362,881 | 19,087,766 | 129,779,060 | 17,340,865 | 470,308 | 195,081,276 | 90,310,412 | 67,154,213 | 14,306 | 912,800 | 19,144 |
| 2 | <u>Current Revenue</u> | \$32,433,692 | \$11,262,377 | \$1,176,138 | \$6,331,332 | \$654,786 | \$98,625 | \$6,712,141 | \$3,243,600 | \$2,846,148 | \$772 | \$106,979 | \$794 |
| 3 | | | | | | | | | | | | | |
| 4 | <u>Generation Marginal Cost</u> | | | | | | | | | | | | |
| 5 | Generation Demand-Related | \$5,368,907 | \$1,681,622 | \$160,628 | \$942,951 | \$119,727 | \$519 | \$1,078,999 | \$563,709 | \$819,581 | \$75 | \$995 | \$100 |
| 6 | Generation Energy-Related | \$46,251,305 | \$13,587,114 | \$1,187,823 | \$7,954,222 | \$1,055,870 | \$28,374 | \$11,838,944 | \$5,800,384 | \$4,741,513 | \$863 | \$55,044 | \$1,155 |
| 7 | Generation Total | \$51,620,212 | \$15,268,735 | \$1,348,451 | \$8,897,174 | \$1,175,597 | \$28,893 | \$12,917,943 | \$6,364,093 | \$5,561,094 | \$938 | \$56,039 | \$1,255 |
| 8 | <u>Transmission Marginal Cost</u> | | | | | | | | | | | | |
| 9 | Transmission Demand-Related (75%) | \$14,714,881 | \$4,912,854 | \$433,698 | \$2,725,422 | \$348,347 | \$2,358 | \$3,117,028 | \$1,404,982 | \$1,765,148 | \$216 | \$4,540 | \$289 |
| 10 | Transmission Energy-Related (25%) | \$4,904,960 | \$1,459,585 | \$126,429 | \$859,599 | \$114,858 | \$3,115 | \$1,292,131 | \$598,176 | \$444,800 | \$95 | \$6,046 | \$127 |
| 11 | Transmission Total | \$19,619,842 | \$6,372,439 | \$560,127 | \$3,585,021 | \$463,205 | \$5,473 | \$4,409,159 | \$2,003,158 | \$2,209,948 | \$311 | \$10,586 | \$416 |
| 12 | <u>Distribution Marginal Cost</u> | | | | | | | | | | | | |
| 13 | Demand-Related | \$9,658,948 | \$4,441,166 | \$280,793 | \$1,812,158 | \$171,415 | \$5,820 | \$1,102,323 | \$0 | \$1,833,817 | \$156 | \$11,191 | \$110 |
| 14 | Customer-Related | \$2,877,137 | \$1,831,719 | \$489,644 | \$230,216 | \$7,279 | \$0 | \$18,994 | \$6,595 | \$289,732 | \$261 | \$1,857 | \$838 |
| 15 | | | | | | | | | | | | | |
| 16 | <u>Total Functionized Revenue Requirement</u> | | | | | | | | | | | | |
| 17 | Generation | \$20,407,194 | \$6,036,241 | \$533,088 | \$3,517,350 | \$464,753 | \$11,422 | \$5,106,895 | \$2,515,939 | \$2,198,486 | \$371 | \$22,154 | \$496 |
| 18 | Transmission | \$3,694,492 | \$1,199,955 | \$105,474 | \$675,073 | \$87,223 | \$1,031 | \$830,262 | \$377,202 | \$416,142 | \$58 | \$1,993 | \$78 |
| 19 | Distribution | | | | | | | | | | | | |
| 20 | Demand-Related | \$10,306,242 | \$4,738,791 | \$299,610 | \$1,933,600 | \$182,902 | \$6,210 | \$1,176,195 | \$0 | \$1,956,711 | \$166 | \$11,941 | \$117 |
| 21 | Customer-Related | | | | | | | | | | | | |
| 22 | Allocated | \$2,611,035 | \$1,662,306 | \$444,358 | \$208,924 | \$6,606 | \$0 | \$17,238 | \$5,985 | \$262,935 | \$237 | \$1,686 | \$760 |
| 23 | Direct Assignment | \$414,826 | \$190,712 | \$42,634 | \$18,964 | \$71 | \$58,699 | \$85 | \$30 | \$21,595 | \$43 | \$81,908 | \$85 |
| 24 | | | | | | | | | | | | | |
| 25 | Total Cost of Service | \$37,433,790 | \$13,828,005 | \$1,425,163 | \$6,353,911 | \$741,555 | \$77,361 | \$7,130,674 | \$2,899,156 | \$4,855,869 | \$876 | \$119,683 | \$1,537 |
| 26 | Revenue Deficiency | \$5,000,098 | \$2,565,628 | \$249,025 | \$22,579 | \$86,769 | (\$21,264) | \$418,533 | (\$344,444) | \$2,009,721 | \$104 | \$12,704 | \$743 |
| 27 | % Increase Required | 15.42% | 22.78% | 21.17% | 0.36% | 13.25% | -21.56% | 6.24% | -10.62% | 70.61% | 13.41% | 11.88% | 93.60% |
| 28 | | | | | | | | | | | | | |
| 29 | <u>Proposed Revenue Spread</u> | \$37,434,662 | \$14,224,869 | \$1,466,066 | \$6,536,268 | \$762,838 | \$98,625 | \$7,335,324 | \$3,243,600 | \$3,641,901 | \$901 | \$123,118 | \$1,153 |
| 30 | % Increase Required | 15.42% | 26.30% | 24.65% | 3.24% | 16.50% | 0.00% | 9.28% | 0.00% | 27.96% | 16.67% | 15.09% | 45.20% |
| 31 | <u>Cost of Service Index</u> | | 102.87% | 102.87% | 102.87% | 102.87% | 127.49% | 102.87% | 111.88% | 75.00% | 102.87% | 102.87% | 75.00% |
| 32 | | | | | | | | | | | | | |
| 2010 October Update APCU (UE 214): Baseline Revenue Requirement Spread Employing the UE 213 Test Period Figures | | | | | | | | | | | | | |
| 33 | 2010 October Update APCU Cost of Service (UE 214) | \$2,391,071 | \$707,255 | \$62,461 | \$412,121 | \$54,454 | \$1,338 | \$598,365 | \$294,788 | \$257,592 | \$43 | \$2,596 | \$58 |
| 34 | 2010 October Update APCU Spread (UE 214) | \$2,391,071 | \$664,879 | \$58,098 | \$392,610 | \$52,174 | \$0 | \$576,407 | \$258,155 | \$386,388 | \$41 | \$2,231 | \$87 |
| 2011 October Update APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 213 Test Period Figures | | | | | | | | | | | | | |
| 35 | 2011 October Update APCU Cost of Service (Allocator – Line 7) | \$1,563,445 | \$462,451 | \$40,841 | \$269,473 | \$35,606 | \$875 | \$391,252 | \$192,752 | \$168,431 | \$28 | \$1,697 | \$38 |
| 36 | Subsidy Correction Determination (+ 50%) | \$84,235 | | | | | | | | \$84,216 | | | \$19 |
| 37 | General Rate Case Subsidy – \$ (Line 29 - Line 25) | \$1,215,224 | \$396,864 | \$40,902 | \$182,357 | \$21,283 | \$21,264 | \$204,650 | \$344,444 | \$0 | \$25 | \$3,435 | \$0 |
| 38 | General Rate Case Subsidy – % | 100.00% | 32.66% | 3.37% | 15.01% | 1.75% | 1.75% | 16.84% | 28.34% | 0.00% | 0.002% | 0.28% | 0.00% |
| 39 | Allocated Subsidy Correction (Allocator – Line 38) | -\$84,235 | -\$27,509 | -\$2,835 | -\$12,640 | -\$1,475 | -\$1,474 | -\$14,186 | -\$23,876 | \$0 | -\$2 | -\$238 | \$0 |
| 40 | <u>Proposed APCU Spread – Preliminary (Lines 35 + 36 + 39)</u> | \$1,563,445 | \$434,942 | \$38,006 | \$256,832 | \$34,131 | -\$599 | \$377,066 | \$168,877 | \$252,647 | \$27 | \$1,459 | \$57 |
| 41 | <u>Proposed October Update APCU Spread (Eliminate the Line 40 negative)</u> | \$1,563,445 | \$434,743 | \$37,989 | \$256,715 | \$34,115 | \$0 | \$376,894 | \$168,800 | \$252,647 | \$27 | \$1,459 | \$57 |
| 42 | % Increase Required Due to APCU (Proposed) (Line 41/(Line 29 + Line 34)) | 3.93% | 2.92% | 2.49% | 3.71% | 4.19% | 0.00% | 4.76% | 4.82% | 6.27% | 2.83% | 1.16% | 4.60% |
| 43 | Total Cost of Service: 2009 General Rate Case Plus Oct. 2010 & 2011 Update APCU Costs (Line 25 + Line 33 + Line 35) | \$41,388,306 | \$14,997,711 | \$1,528,465 | \$7,035,505 | \$831,616 | \$79,575 | \$8,120,290 | \$3,386,696 | \$5,281,892 | \$947 | \$123,976 | \$1,633 |
| 44 | Proposed Combined Revenue Spread (Line 29 + Line 34 + Line 41) | \$41,389,178 | \$15,324,492 | \$1,562,152 | \$7,185,593 | \$849,127 | \$98,625 | \$8,288,625 | \$3,670,555 | \$4,280,937 | \$968 | \$126,807 | \$1,297 |
| 45 | <u>Revised Cost of Service Index (Line 44/Line 43)</u> | | 102.18% | 102.20% | 102.13% | 102.11% | 123.94% | 102.07% | 108.38% | 81.05% | 102.18% | 102.28% | 79.41% |
| 46 | <u>Loss-Adjusted 2009 Normalized Sales (kWh) (Ex. Idaho Power/1212)</u> | 679,301,864 | 198,558,922 | 17,201,052 | 116,956,858 | 16,177,273 | 424,083 | 181,464,005 | 87,112,615 | 60,553,810 | 12,900 | 823,084 | 17,262 |
| 47 | 2011 October Update APCU Incremental Rate given 2009 Test Period Sales (Mills per kWh) (1000*(Line 41/Line 46)) | 2.302 | 2.189 | 2.209 | 2.195 | 2.109 | 0.000 | 2.077 | 1.938 | 4.172 | 2.066 | 1.772 | 3.303 |
| 48 | <u>APCU Incremental Rate for 2011 October Update (Mills per kWh) (Line 47*(Column A/(Line 46/Line 49)))</u> | 2.400 | 2.283 | 2.302 | 2.288 | 2.199 | 0.000 | 2.165 | 2.020 | 4.350 | 2.153 | 1.847 | 3.444 |
| 49 | <u>Loss-Adjusted 2011-2012 Normalized Sales (kWh)</u> | 651,435,404 | 198,487,716 | 17,901,437 | 114,644,272 | 17,980,268 | 483,936 | 180,186,197 | 74,306,436 | 46,637,806 | 12,900 | 778,108 | 16,328 |
| 50 | <u>Projected October Update APCU 2011-2012 Revenues (Line 49 * Line 48)</u> | \$1,540,799 | \$453,147 | \$41,209 | \$262,306 | \$39,539 | \$0 | \$390,103 | \$150,099 | \$202,874 | \$28 | \$1,437 | \$56 |

NOTES:

- 1 2011 October Update APCU Revenues = \$2.40/MWh x 651,435,404 MW's = **\$ 1,563,445** (Line 35, Column A)
2 \$2.40 = \$16.96 (2011 October APCU Rate) - \$14.56 (2010 October APCU Rate)

IDAHO POWER COMPANY
Rate Spread Exhibit for March Forecast APCU

Idaho Power/204
Wright/2

| General Rate Case (UE 213) Plus the 2010 October APCU Update: Marginal Cost-of-Service Study and Revenue Spread | | | | | | | | | | | | | |
|---|---|--------------------------------|--------------------|----------------|-----------------------------|---------------------------|-------------------------|----------------------------|--------------------------|--------------------------------|---------------------------------|------------------------------|---------------------------|
| 2009 Test Period | | | | | | | | | | | | | |
| Line | Description | (A) TOTAL SYSTEM/AVERAGE | (B) RESIDENTIAL | (C) GEN SRV | (D) GEN SRV SECONDARY | (E) GEN SRV PRIMARY | (F) AREA LIGHTING | (G) LG POWER PRIMARY | (H) LG POWER TRANS | (I) IRRIGATION SECONDARY | (J) UNMETERED GEN SERVICE | (K) MUNICIPAL ST LIGHT | (L) TRAFFIC CONTROL |
| | | (1) | (7) | (9-S) | (9-P) | (15) | (19-P) | (19-T) | (24-S) | (40) | (41) | (42) | |
| 1 | Loss-Inflated Normalized Sales (kWh) | 740,533,031 | 220,362,881 | 19,087,766 | 129,779,060 | 17,340,865 | 470,308 | 195,081,276 | 90,310,412 | 67,154,213 | 14,306 | 912,800 | 19,144 |
| 2 | Current, i.e., pre-General Rate Case, Base Revenues | \$32,433,692 | \$11,262,377 | \$1,176,138 | \$6,331,332 | \$654,786 | \$98,625 | \$6,712,141 | \$3,243,600 | \$2,846,148 | \$772 | \$106,979 | \$794 |
| 3 | | | | | | | | | | | | | |
| 4 | Generation Marginal Cost | | | | | | | | | | | | |
| 5 | Generation Demand-Related | \$5,368,907 | \$1,681,622 | \$160,628 | \$942,951 | \$119,727 | \$519 | \$1,078,999 | \$563,709 | \$819,581 | \$75 | \$995 | \$100 |
| 6 | Generation Energy-Related | \$46,251,305 | \$13,587,114 | \$1,187,823 | \$7,954,222 | \$1,055,870 | \$28,374 | \$11,838,944 | \$5,800,384 | \$4,741,513 | \$863 | \$55,044 | \$1,155 |
| 7 | Generation Total | \$51,620,212 | \$15,268,735 | \$1,348,451 | \$8,897,174 | \$1,175,597 | \$28,893 | \$12,917,943 | \$6,364,093 | \$5,561,094 | \$938 | \$56,039 | \$1,255 |
| 8 | Transmission Marginal Cost | | | | | | | | | | | | |
| 9 | Transmission Demand-Related (75%) | \$14,714,881 | \$4,912,854 | \$433,698 | \$2,725,422 | \$348,347 | \$2,358 | \$3,117,028 | \$1,404,982 | \$1,765,148 | \$216 | \$4,540 | \$289 |
| 10 | Transmission Energy-Related (25%) | \$4,904,960 | \$1,459,585 | \$126,429 | \$859,599 | \$114,858 | \$3,115 | \$1,292,131 | \$598,176 | \$444,800 | \$95 | \$6,046 | \$127 |
| 11 | Transmission Total | \$19,619,842 | \$6,372,439 | \$560,127 | \$3,585,021 | \$463,205 | \$5,473 | \$4,409,159 | \$2,003,158 | \$2,209,948 | \$311 | \$10,586 | \$416 |
| 12 | Distribution Marginal Cost | | | | | | | | | | | | |
| 13 | Demand-Related | \$9,658,948 | \$4,441,166 | \$280,793 | \$1,812,158 | \$171,415 | \$5,820 | \$1,102,323 | \$0 | \$1,833,817 | \$156 | \$11,191 | \$110 |
| 14 | Customer-Related | \$2,877,137 | \$1,831,719 | \$489,644 | \$230,216 | \$7,279 | \$0 | \$18,994 | \$6,595 | \$289,732 | \$261 | \$1,857 | \$838 |
| 15 | | | | | | | | | | | | | |
| 16 | Total Functionized Revenue Requirement | | | | | | | | | | | | |
| 17 | Generation | \$20,407,194 | \$6,036,241 | \$533,088 | \$3,517,350 | \$464,753 | \$11,422 | \$5,106,895 | \$2,515,939 | \$2,198,486 | \$371 | \$22,154 | \$496 |
| 18 | Transmission | \$3,694,492 | \$1,199,955 | \$105,474 | \$87,073 | \$87,223 | \$1,031 | \$830,262 | \$377,202 | \$416,142 | \$58 | \$1,993 | \$78 |
| 19 | Distribution | | | | | | | | | | | | |
| 20 | Demand-Related | \$10,306,242 | \$4,738,791 | \$299,610 | \$1,933,600 | \$182,902 | \$6,210 | \$1,176,195 | \$0 | \$1,956,711 | \$166 | \$11,941 | \$117 |
| 21 | Customer-Related | | | | | | | | | | | | |
| 22 | Allocated | \$2,611,035 | \$1,662,306 | \$444,358 | \$208,924 | \$6,606 | \$0 | \$17,238 | \$5,985 | \$262,935 | \$237 | \$1,686 | \$760 |
| 23 | Direct Assignment | \$414,826 | \$190,712 | \$42,634 | \$18,964 | \$71 | \$58,699 | \$85 | \$30 | \$21,595 | \$43 | \$81,908 | \$85 |
| 24 | | | | | | | | | | | | | |
| 25 | Total Cost of Service | \$37,433,790 | \$13,828,005 | \$1,425,163 | \$6,353,911 | \$741,555 | \$77,361 | \$7,130,674 | \$2,899,156 | \$4,855,869 | \$876 | \$119,683 | \$1,537 |
| 26 | Revenue Efficiency | \$5,000,098 | \$2,565,628 | \$249,025 | \$22,579 | \$86,769 | (\$21,264) | \$418,533 | (\$344,444) | \$2,009,721 | \$104 | \$12,704 | \$743 |
| 27 | % Increase Required | 15.42% | 22.78% | 21.17% | 0.36% | 13.25% | -21.56% | 6.24% | -10.62% | 70.61% | 13.41% | 11.88% | 93.60% |
| 28 | | | | | | | | | | | | | |
| 29 | Ordered General Rate Case Revenue Spread | \$37,434,662 | \$14,224,869 | \$1,466,066 | \$6,536,268 | \$762,838 | \$98,625 | \$7,335,324 | \$3,243,600 | \$3,641,901 | \$901 | \$123,118 | \$1,153 |
| 30 | % Increase Required | 15.42% | 26.30% | 24.65% | 3.24% | 16.50% | 0.00% | 9.28% | 0.00% | 27.96% | 16.67% | 15.09% | 45.20% |
| 31 | Cost of Service Index | | 102.87% | 102.87% | 102.87% | 102.87% | 127.49% | 102.87% | 111.88% | 75.00% | 102.87% | 102.87% | 75.00% |
| 32a | Total Cost of Service: 2009 General Rate Case Plus 2010 & 2011 Oct. Update APCU Costs | \$ 41,388,306 | \$ 14,997,711 | \$ 1,528,465 | \$ 7,035,505 | \$ 831,616 | \$ 79,575 | \$ 8,120,290 | \$ 3,386,696 | \$ 5,281,892 | \$ 947 | \$ 123,976 | \$ 1,633 |
| 32b | Combined Spread: 2009 General Rate Case Plus 2010 & 2011 Oct. Update APCU Costs | \$ 41,389,178 | \$ 15,324,492 | \$ 1,562,152 | \$ 7,185,593 | \$ 849,127 | \$ 98,625 | \$ 8,288,625 | \$ 3,670,555 | \$ 4,280,937 | \$ 968 | \$ 126,807 | \$ 1,297 |
| 33 | Adjusted Subsidy -- \$ [Line 32a - Line 32b] | \$ (873) | \$ (326,781) | \$ (33,687) | \$ (150,089) | \$ (17,512) | \$ (19,050) | \$ (168,334) | \$ (283,859) | \$ 1,000,955 | \$ (21) | \$ (2,831) | \$ 336 |
| 2011 March Forecast APCU: Baseline Revenue Requirement Spread and Rate Development Employing the UE 213 Test Period Figures | | | | | | | | | | | | | |
| 34 | 2011 March APCU Cost of Service (Allocator -- Line 7) | \$664,464 | \$196,542 | \$17,357 | \$114,526 | \$15,132 | \$372 | \$166,282 | \$81,920 | \$71,583 | \$12 | \$721 | \$16 |
| 35 | Subsidy Correction Determination (+ 50%) | \$35,800 | | | | | | | | \$35,792 | | | \$8 |
| 36 | Adjusted Subsidy, Negative Values -- \$ (Line 33) | \$1,002,164 | \$326,781 | \$33,687 | \$150,089 | \$17,512 | \$19,050 | \$168,334 | \$283,859 | \$0 | \$21 | \$2,831 | \$0 |
| 37 | Adjusted Subsidy, Negative Values -- % | 100.00% | 32.61% | 3.36% | 14.98% | 1.75% | 1.90% | 16.80% | 28.32% | 0.00% | 0.002% | 0.28% | 0.00% |
| 38 | Allocated Subsidy Correction (Allocator -- Line 37) | -\$35,800 | -\$11,673 | -\$1,203 | -\$5,362 | -\$626 | -\$681 | -\$6,013 | -\$10,140 | \$0 | -\$1 | -\$101 | \$0 |
| 39 | Proposed 2011 March Update APCU Spread -- Preliminary (Lines 34 + 35 + 38) | \$664,464 | \$184,868 | \$16,154 | \$109,164 | \$14,507 | -\$309 | \$160,269 | \$71,780 | \$107,375 | \$11 | \$620 | \$24 |
| 40 | Proposed 2011 March Update APCU Spread (Eliminate the Line 39-negative) | \$664,464 | \$184,766 | \$16,145 | \$109,104 | \$14,499 | \$0 | \$160,180 | \$71,740 | \$107,375 | \$11 | \$620 | \$24 |
| 41 | % Increase Required Due to March Update APCU (Proposed) (Line 40/Line 32b) | 1.61% | 1.21% | 1.03% | 1.52% | 1.71% | 0.00% | 1.93% | 1.95% | 2.51% | 1.17% | 0.49% | 1.87% |
| 42 | Total Cost of Service: 2009 General Rate Case Plus 2010 & 2011 October and March APCU Cost Adjustments (Line 32a + Line 34) | \$42,052,770 | \$15,194,253 | \$1,545,823 | \$7,150,030 | \$846,748 | \$79,947 | \$8,286,572 | \$3,468,615 | \$5,353,476 | \$959 | \$124,697 | \$1,649 |
| 43 | Proposed Combined Revenue Spread (Line 32b + Line 40) | \$42,053,643 | \$15,509,258 | \$1,578,298 | \$7,294,697 | \$863,626 | \$98,625 | \$8,448,805 | \$3,742,295 | \$4,388,312 | \$979 | \$127,427 | \$1,321 |
| 44 | Revised Cost of Service Index (Line 43/Line 42) | | 102.07% | 102.10% | 102.02% | 101.99% | 123.36% | 101.96% | 107.89% | 81.97% | 102.08% | 102.19% | 80.11% |
| 45 | Loss-Adjusted 2009 Normalized Sales (kWh) (Ex. Idaho Power/1212) | 679,301,864 | 198,558,922 | 17,201,052 | 116,956,858 | 16,177,273 | 424,083 | 181,464,005 | 87,112,615 | 60,553,810 | 12,900 | 823,084 | 17,262 |
| 46 | March Forecast APCU Incremental Rate Given 2009 Test Period Sales (Mills per kWh) (1000*(Line 40/Line 45)) | 0.978 | 0.931 | 0.939 | 0.933 | 0.896 | 0.000 | 0.883 | 0.824 | 1.773 | 0.878 | 0.753 | 1.404 |
| 47 | APCU Incremental Rate for 2011 March Forecast (Mills per kWh) (Line 46*(Column A:[Line 45/Line 48])) | 1.020 | 0.970 | 0.978 | 0.972 | 0.934 | 0.000 | 0.920 | 0.858 | 1.849 | 0.915 | 0.785 | 1.463 |
| 48 | Loss-Adjusted 2011-2012 Normalized Sales (kWh) | 651,435,404 | 198,487,716 | 17,901,437 | 114,644,272 | 17,980,268 | 483,936 | 180,186,197 | 74,306,436 | 46,637,806 | 12,900 | 778,108 | 16,328 |
| 49 | Projected March Forecast APCU 2011-2012 Revenues (Line 47 * Line 48) | \$654,675 | \$192,533 | \$17,508 | \$111,434 | \$16,794 | \$0 | \$165,771 | \$63,755 | \$86,233 | \$12 | \$611 | \$24 |

NOTES:

1 2011 March Forecast APCU Revenues = \$1.02/MWh x 651,435,404 MW's = \$ 664,464 (Line 34, Column A)

Idaho Power/205
Witness: Scott Wright

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 222
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

Summary of Revenue Charge

March 23, 2011

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 APCU March Forecast Filing
Effective June 1, 2011

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

| Line No | Tariff Description | Rate Sch. No. | Average Number of Customers (1) | 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 |
|------------------------------|---------------------------------|---------------------|---------------------------------------|-----------------------------------|------------------------------|------------------|--|-------------------------------------|------------------|--|
| <u>Uniform Tariff Rates:</u> | | | | | | | | | | |
| 1 | Residential Service | 1 | 13,611 | 198,487,716 | \$15,790,709 | 79.56 | (\$264,386) | \$15,526,323 | 78.22 | (1.67%) |
| 2 | Small General Service | 7 | 2,485 | 17,901,437 | \$1,606,198 | 89.72 | (\$24,078) | \$1,582,121 | 88.38 | (1.50%) |
| 3 | Large General Service | 9 | 901 | 132,624,541 | \$8,258,646 | 62.27 | (\$176,235) | \$8,082,411 | 60.94 | (2.13%) |
| 4 | Dusk to Dawn Lighting | 15 | 0 | 483,936 | \$112,463 | 232.39 | \$0 | \$112,463 | 232.39 | 0.00% |
| 5 | Large Power Service | 19 | 7 | 254,492,633 | \$11,931,759 | 46.88 | (\$315,438) | \$11,616,321 | 45.65 | (2.64%) |
| 6 | Agricultural Irrigation Service | 24 | 1,588 | 46,637,806 | \$3,658,379 | 78.44 | (\$118,367) | \$3,540,011 | 75.90 | (3.24%) |
| 7 | Unmetered General Service | 40 | 3 | 12,900 | \$999 | 77.43 | (\$16) | \$983 | 76.19 | (1.60%) |
| 8 | Street Lighting | 41 | 14 | 778,108 | \$125,313 | 161.05 | (\$851) | \$124,462 | 159.95 | (0.68%) |
| 9 | Traffic Control Lighting | 42 | 6 | 16,328 | \$1,288 | 78.88 | (\$33) | \$1,255 | 76.85 | (2.57%) |
| 10 | Total Uniform Tariffs | | 18,615 | 651,435,405 | \$41,485,753 | 63.68 | (\$899,404) | \$40,586,349 | 62.30 | (2.17%) |
| 12 | Total Oregon Retail Sales | | 18,615 | 651,435,405 | \$41,485,753 | 63.68 | (\$899,404) | \$40,586,349 | 62.30 | (2.17%) |

(1) April 1, 2011 - March 31, 2012 APCU Forecasted Test Year