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October 20, 2010

## VIA ELECTRONIC AND U.S. MAIL

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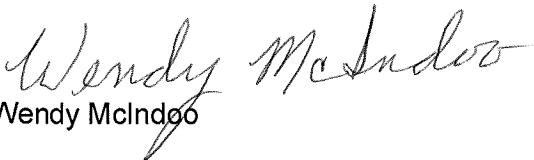
**Re: UE 222 - In The Matter of IDAHO POWER COMPANY 2011 Annual Power Cost Update**

Attention Filing Center:

Enclosed for filing in the above captioned docket is the original and five copies of the testimony of Scott Wright (Idaho Power/100-107) in support of Advice Filing 10-16 which was filed on October 15, 2010. A copy of this document 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,

  
Wendy McIndoo

cc: Service List

1

**CERTIFICATE OF SERVICE**

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

5	Michael T. Weirich, Assistant AG Department of Justice 1162 Court Street NE Salem, OR 97301-4096 michael.weirich@state.or.us	Ed Durrenberger Public Utility Commission of Oregon P.O. Box 2148 Salem, OR 97308-2148 ed.durrenberger@state.or.us
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14		

15        DATED: October 20, 2010

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Wendy McIndoo  
Legal Assistant

Idaho Power/100  
Witness: Scott Wright

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**UE 222**

IN THE MATTER OF IDAHO POWER )  
COMPANY'S 2011 ANNUAL POWER )  
COST UPDATE )  
OCTOBER UPDATE )  
                                )  
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**IDAHO POWER COMPANY  
DIRECT TESTIMONY  
OF  
SCOTT WRIGHT**

October 20, 2010

1           **Q.     Please state your name, business address, and present occupation.**

2           A.     My name is Scott Wright. I am employed by Idaho Power Company ("Idaho  
3 Power" or "Company") as a Regulatory Analyst in the Regulatory Affairs Department. My  
4 business address is 1221 West Idaho Street, Boise, Idaho 83702.

5           **Q.     Please describe your educational background.**

6           A.     I received a Bachelor of Science degree in Business Economics from Eastern  
7 Oregon University. I have also attended the Center for Public Utilities "Practical Skills for a  
8 Changing Electric Industry" course at New Mexico State University in Albuquerque, New  
9 Mexico, as well as the Edison Electric Institute "Electric Rate Advanced Course" in Madison,  
10 Wisconsin.

11          **Q.     Please describe your work experience.**

12          A.     In May 1998, I accepted a position as Research Assistant with Idaho Power  
13 in the Regulatory Affairs Department. In March 2007, I was promoted to a Regulatory  
14 Analyst. As a Regulatory Analyst, I am responsible for running the AURORAxmp model to  
15 calculate net power supply expenses ("NPSE") for ratemaking purposes, as well as the  
16 marginal cost of energy used in the Company's marginal cost analysis. My duties also  
17 include providing analytical support for other regulatory activities within the Regulatory  
18 Affairs Department. In my current role, I served as the Company's power supply expense  
19 witness in the last two Annual Power Cost Update filings before the Oregon Public Utility  
20 Commission ("Commission"), UE-203 and UE-214.

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

22          A.     The purpose of my testimony is to describe the Company's October Update  
23 for the 2011 Annual Power Cost Update ("APCU"), which is required as detailed in Order  
24 No. 08-238.

25          **Q.     What is the October Update?**

26

1       A.     The October Update is the Company's estimate of what "normal" power  
2 supply expenses will be for an upcoming water year. In this case, the water year is April  
3 2011 through March 2012.

4       **Q.     Was the AURORA model used for this October Update?**

5       A.     Yes.

6       **Q.     Please describe the AURORA model and how it is used by the**  
7 **Company.**

8       A.     The AURORA model is a comprehensive electric market resource dispatch  
9 model. The Company uses AURORA to determine the economic dispatch of its resources  
10 to determine normal net power supply expense based upon results from a range of historical  
11 water conditions.

12      **Q.     Please describe the variables that are to be updated in the AURORA**  
13 **model as delineated in Order No. 08-238.**

14      A.     Order No. 08-238 identifies a number of variables to be updated in the  
15 AURORA model annually in October: loads, fuel prices, transportation costs, maintenance  
16 rates, heat rates, and forced outage rates for the thermal plants. This year's update is for  
17 the April 2011 through March 2012 test year and reflects updated plant capacities for all  
18 Company owned resources as well as an updated Sales and Load Forecast.

19       Natural gas prices were updated using the forecast methodology used in the  
20 Company's Integrated Resource Plan. This methodology uses the Northwest Power and  
21 Conservation Council, New York Mercantile Exchange (NYMEX), Natural Gas Exchange  
22 (NGX), Energy Information Administration (EIA) and Moody's forecast data to develop a  
23 normalized gas price that is used for ratemaking purposes. The normalization process  
24 reduces the impact of volatility that may occur in the short term gas market.

25       PURPA contracts and other wholesale contracts were updated to reflect expected  
26 costs during the April 2011 through March 2012 test year.

1       **Q. Have you prepared an exhibit to demonstrate the normalization of**  
2 **variable power supply expenses for this scenario?**

3       A. Yes. Exhibit No. 101 shows the results of the variable power supply expense  
4 normalization modeling for the April 2011 through March 2012 test year. Exhibit No. 101  
5 shows the summary results containing the 82-year average variable power supply  
6 generation sources and expenses.

7       **Q. Please summarize the sources and disposition of energy shown on**  
8 **Exhibit No. 101.**

9       A. Hydro generation supplies 8.7 million megawatt-hours (MWh), approximately  
10 48 percent ( $8.7 \text{ million MWh} / 18 \text{ million MWh} = 48 \text{ percent}$ ) of the generation mix. Thermal  
11 generation supplies 6.3 million MWh (Bridger 4.44, Boardman 0.34, Valmy 1.5),  
12 approximately 35 percent ( $6.3 \text{ million MWh} / 18 \text{ million MWh} = 35 \text{ percent}$ ) of the generation  
13 mix. Danskin and Bennett Mountain are peaking units supplying energy at times when  
14 resources and/or transmission lines are constrained. Purchases of power are made up of  
15 short term and longer term market purchases, and PURPA. PURPA purchases are  
16 normalized and account for nearly 1.7 million MWh. PURPA purchases are not included on  
17 Exhibit No. 101; however, when combined with market purchases of 1.3 million MWh, total  
18 purchases amount to 3 million MWh ( $1.7 \text{ million MWh} + 1.3 \text{ million MWh} = 3 \text{ million MWh}$ ) or  
19 approximately 17 percent ( $3 \text{ million MWh} / 18 \text{ million MWh} = 17 \text{ percent}$ ) of the generation  
20 mix. Of the 18 million MWh consumed, 16.1 million MWh are utilized for system loads while  
21 nearly 1.9 million MWh are sold as surplus.

22       **Q. Please quantify the changes in coal prices from last year's October**  
23 **filing.**

24       A. Coal prices for each of the Company's coal-fired thermal generation plants  
25 have been updated to reflect current operating costs. The coal prices at the Bridger plant  
26 have increased from \$21.32 per MWh to \$22.33 per MWh. The coal prices at the Boardman

1 plant have increased from \$18.25 per MWh to \$18.65 per MWh. The coal prices at the  
2 Valmy plant have decreased from \$30.94 per MWh to \$29.09 per MWh.

3       **Q. Please describe the change in PURPA generation and expenses since**  
4 **last year's October filing.**

5       A.     PURPA generation has increased from 193 average megawatts (aMW) to  
6 195 aMW, an increase of 2 aMW. PURPA expenses have also increased from \$117.6  
7 million to \$129.1 million, an increase of \$11.5 million.

8       **Q. Please explain the treatment of PURPA expense in Oregon.**

9       A.     Many of the PURPA contracts have payment provisions that require the  
10 Company to provide leveled monthly payments over the length of the contract. Oregon  
11 regulation requires the Company to reflect a non-leveled payment stream in rates, rather  
12 than the leveled monthly payment stream. The Oregon method provides benefits in the  
13 early years of the contract by paying less than the actual contract levels. As time passes,  
14 the non-leveled method required in Oregon begins to exceed the leveled monthly  
15 payment stream, therefore reflecting the higher re-priced costs.

16       **Q. Please describe the change in the Company's system loads since last**  
17 **year's October filing.**

18       A.     The Company's annual normalized system load used in last year's April 2010  
19 through March 2011 filing was 1,817 aMW. The Company's April 2011 through March 2012  
20 annual normalized system load used in this filing is 1,826 aMW, an increase of  
21 approximately 0.5 percent.

22       **Q. Does the normalized system load for the April 2011 through March 2012**  
23 **test period include expected loads from Special Contract customer Hoku Materials,**  
24 **Inc. ("Hoku")?**

25       A.     Yes. Hoku, a manufacturer of solar panels, is now expected to begin taking  
26 electric service from Idaho Power in January 2011.

1           **Q. Please explain the Hoku contract.**

2           A.     The Electric Service Agreement ("ESA") between the Company and Hoku  
3 includes a rate structure that is separated into two blocks. The first block of the contract rate  
4 structure charges market-based rates, while the second block charges embedded rates.  
5 The first block energy-related revenues are subtracted from the NPSE in a similar manner to  
6 the treatment of surplus sales, which also reduce NPSE.

7           **Q. How is the Hoku ESA treated in your NPSE calculations?**

8           A.     The Hoku ESA loads were included during the April 2011 through March  
9 2012 time period, while first block energy-related revenues were subtracted from the NPSE  
10 as mentioned above.

11          **Q. What forward price curve did the Company use to re-price purchased  
12 power and surplus sales?**

13          A.     For the October Update, the Company used the methodology approved in  
14 Order No. 08-238. This methodology uses a one-year average of the daily forward price  
15 curves for April 2012 through March 2013 shown in Exhibit No. 102, which is then  
16 discounted for inflation back to April 2011 through March 2012 according to the quarterly  
17 inflation indices provided on Exhibit No. 103.

18          **Q. What are the average forward price curves the Company used to re-  
19 price purchased power and surplus sales for the normalized test year?**

20          A.     Exhibit No.104 shows the revised monthly prices for April 2011 through  
21 March 2012. These are considered the "normal" forward prices used to re-price the  
22 Company's purchased power and surplus sales estimates for the normalized test year as set  
23 forth in Order No 08-238.

24          **Q. How does the re-pricing of purchased power and surplus sales, using a  
25 "normal" forward price curve, change the purchased power expenses and surplus  
26 sales revenues as modeled by AURORA?**

1       A.     Exhibit No. 101 shows the purchased power expenses and surplus sales  
2 revenues before re-pricing. Exhibit No. 105 shows the same normalized generation  
3 dispatch, with purchased power and surplus sales re-priced using the normalized forward  
4 price curve shown in Exhibit No. 104. A comparison of Exhibit No. 101 and Exhibit No. 105  
5 demonstrates the changes due to re-pricing. Purchased power expenses increase by \$5.8  
6 million, moving from \$36.3 million to \$42.1 million. Surplus sales revenues increase by  
7 \$21.6 million, moving from \$61.3 million to \$82.9 million.

8       Q.     **Does the methodology used to estimate the power supply expenses**  
9 **represented in Exhibit No. 104 conform with the methodology detailed in Order No.**  
10 **08-238?**

11      A.     Yes, it does.

12      Q.     **What is the October Update unit cost per megawatt-hour (\$/MWh)**  
13 **represented by this filing?**

14      A.     Exhibit No. 105 shows the normalized annual sales at customer level for the  
15 April 2011 through March 2012 test year are 14,624,935 MWh. Based upon test year sales,  
16 the cost per unit for the October Update to become effective on June 1, 2011, is \$16.92 per  
17 MWh (\$247.5 million / 14,625 million MWh = \$16.92 per MWh).

18      Q.     **How does this \$16.92 per MWh October Update compare to the October**  
19 **Update that resulted from last year's computation?**

20      A.     The October Update unit cost which became effective June 1, 2010, was  
21 \$14.56 per MWh. This year's October Update of \$16.92 per MWh equates to an increase of  
22 \$2.36 per MWh (\$16.92 – \$14.56 = \$2.36).

23      Q.     **Please explain how the revenue requirement for the October Update is**  
24 **calculated using the unit cost of \$2.36 per MWh.**

25

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1           A.     The revenue requirement for the October Update is calculated by multiplying  
2 the unit cost of \$2.36 per MWh by the loss adjusted sales for the April 2011 through March  
3 2012 test period of 14,624,935 MWh creating a revenue requirement of \$1.6 million.

4           Q.     **What method of allocation are you proposing to spread the incremental  
5 revenue requirement associated with the October Update to the various customer  
6 classes?**

7           A.     I am proposing to allocate the incremental revenue requirement associated  
8 with the 2011 October Update according to the revenue spread methodology approved by  
9 the Commission in UE-214, Order No. 10-191. Order No. 10-191 established a revenue  
10 spread methodology whereby the revenue requirement for the October Update is allocated  
11 to individual customer classes on the basis of the total generation-related revenue  
12 requirement approved in the Company's last general rate case, UE-213. The Commission's  
13 preferred allocation methodology further applies a subsidy correction adjustment to any  
14 customer class whose final revenue allocation in UE-213 was below the cost of service  
15 revenue requirement. As a result of applying the subsidy correction adjustment in this case,  
16 Irrigation Service and Traffic Control Lighting Service receive a revenue increase equal to  
17 150 percent of the 2011 October Update cost of service revenue requirement. The  
18 proposed revenue spread resulting from the application of the Commission-approved  
19 allocation methodology is shown on Exhibit 106.

20          Q.     **What is the overall revenue impact of this year's October Update  
21 compared to last year's October Update using the rate spread methodology described  
22 above?**

23          A.     The overall revenue impact of the October Update compared to last year's  
24 October Update is a 3.72 percent increase.

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1       Q.     Have you supervised the preparation of an exhibit showing the  
2 summary of revenue impact resulting from the October Update proposed by the  
3 Company?

4       A.     Yes. Exhibit No. 107 provides a summary of the revenue change resulting  
5 from this year's October Update as compared to current revenue. The revenue amounts  
6 shown on Exhibit No. 107 may differ slightly from the revenue requirement amounts shown  
7 on Exhibit No. 106 because of rounding and the rate design process. For example, Exhibit  
8 No. 106 shows a cents per kWh for Schedule 41 – Municipal Street Lights. However, in the  
9 rate design process, this amount is converted to a cents per lamp charge. The end result is  
10 a slight difference from the revenue requirement amount shown on Exhibit No. 106.

11      Q.     Has the Company filed draft tariff sheets that reflect the proposed  
12 changes?

13      A.     Yes. The Company has filed draft tariff sheets that reflect the October  
14 Update which will become effective on June 1, 2011.

15      Q.     Does this conclude your testimony?

16      A.     Yes it does.

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Idaho Power/101  
Witness: Scott Wright

**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 2011 – March 2012  
Normalized Loads Over 82 Water Year Conditions

October 20, 2010

IDAHO POWER COMPANY POWER SUPPLY COSTS FOR APRIL 2011 - MARCH 2012 NORMALIZED LOADS OVER 82 WATER YEAR CONDITIONS

AVERAGE

	<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)	867,949.5	930,919.1	924,339.4	667,955.2	556,490.3	554,503.0	524,620.1	457,375.2	679,984.7	804,297.2	850,670.6	868,324.1	8,687,428.5
Bridger													
Energy (MWh)	269,097.0	223,919.7	235,715.2	428,971.2	450,657.5	410,997.7	443,300.9	444,779.0	475,098.4	382,136.4	340,213.4	331,417.1	4,436,303.7
Cost (\$ x 1000)	\$ 6,048.0	\$ 5,048.8	\$ 5,330.4	\$ 9,559.0	\$ 10,017.2	\$ 9,171.5	\$ 9,871.4	\$ 9,873.3	\$ 10,516.8	\$ 8,579.4	\$ 7,634.1	\$ 7,428.7	\$ 99,078.6
Boardman													
Energy (MWh)	13,424.9	1,589.8	21,421.0	37,479.9	37,663.3	35,393.9	35,441.0	34,579.8	37,698.8	29,564.0	28,351.0	30,703.2	343,310.5
Cost (\$ x 1000)	\$ 248.8	\$ 29.9	\$ 400.9	\$ 666.6	\$ 669.7	\$ 631.8	\$ 635.5	\$ 619.3	\$ 670.2	\$ 612.1	\$ 585.0	\$ 632.1	\$ 6,401.8
Valmy													
Energy (MWh)	62,928.4	50,655.6	52,006.0	157,189.8	168,344.5	159,260.2	163,937.5	161,533.8	171,046.8	135,220.6	112,066.3	103,686.5	1,497,876.0
Cost (\$ x 1000)	\$ 1,831.8	\$ 1,485.9	\$ 1,526.4	\$ 4,518.2	\$ 4,832.3	\$ 4,580.5	\$ 4,724.1	\$ 4,644.7	\$ 4,903.7	\$ 4,057.2	\$ 3,362.7	\$ 3,110.8	\$ 43,578.2
Danskin													
Energy (MWh)	-	-	-	35.1	2,386.8	2,558.7	499.5	1.6	-	0.9	-	-	5,482.6
Cost (\$ x 1000)	\$ -	\$ -	\$ -	\$ 2.0	\$ 144.4	\$ 155.0	\$ 31.7	\$ 0.1	\$ -	\$ 0.1	\$ -	\$ -	\$ 333.3
Fixed Capacity Charge - Gas Transportation (\$ x 1000)	\$ 402.1	\$ 413.2	\$ 400.6	\$ 413.2	\$ 413.2	\$ 400.6	\$ 413.2	\$ 400.6	\$ 413.2	\$ 311.0	\$ 283.1	\$ 364.0	\$ 4,628.2
Total Cost	\$ 402.1	\$ 413.2	\$ 402.6	\$ 559.0	\$ 568.9	\$ 432.2	\$ 413.3	\$ 400.6	\$ 413.3	\$ 311.0	\$ 283.1	\$ 364.0	\$ 4,963.5
Bennett Mountain													
Energy (MWh)	-	-	-	5.8	192.8	114.0	19.5	-	-	-	-	-	332.2
Cost (\$ x 1000)	\$ -	\$ -	\$ -	\$ 0.3	\$ 11.8	\$ 7.2	\$ 1.3	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 20.6
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	5,879.6	32,230.0	95,139.9	258,831.6	241,098.3	98,411.0	2,654.7	8,311.2	50,752.2	51,393.0	8,944.5	3,923.7	857,569.7
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. PURPA (MWh)	32,965.7	63,036.6	159,059.1	325,188.0	303,655.8	120,421.0	33,838.9	38,054.2	87,669.5	81,447.1	34,865.2	29,639.5	1,309,840.5
Market Cost (\$ x 1000)	\$ 174.9	\$ 1,071.2	\$ 2,821.6	\$ 11,600.0	\$ 11,435.1	\$ 4,668.0	\$ 107.5	\$ 341.4	\$ 2,812.8	\$ 1,586.5	\$ 312.4	\$ 117.1	\$ 37,048.4
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. PURPA (\$ x 1000)	\$ 1,267.0	\$ 2,312.0	\$ 7,568.5	\$ 16,836.4	\$ 16,464.9	\$ 5,880.0	\$ 1,816.4	\$ 2,298.2	\$ 5,236.0	\$ 3,271.5	\$ 1,768.9	\$ 1,182.1	\$ 65,901.9
Surplus Sales													
Energy (MWh)	325,456.9	173,770.1	87,737.0	11,507.4	16,209.9	109,547.1	221,399.2	98,327.3	124,883.8	116,677.1	288,949.7	333,110.1	1,907,575.6
Revenue Including Transmission Costs (\$ x 1000)	\$ 9,294.2	\$ 4,607.3	\$ 1,927.6	\$ 342.2	\$ 500.6	\$ 3,465.5	\$ 8,912.6	\$ 4,122.6	\$ 5,696.7	\$ 3,808.1	\$ 8,964.8	\$ 10,322.8	\$ 61,965.0
Transmission Costs (\$ x 1000)	\$ 325.5	\$ 173.8	\$ 87.7	\$ 11.5	\$ 16.2	\$ 109.5	\$ 221.4	\$ 98.3	\$ 124.9	\$ 116.7	\$ 288.9	\$ 333.1	\$ 1,907.6
Revenue Excluding Transmission Costs (\$ x 1000)	\$ 8,968.7	\$ 4,433.6	\$ 1,839.9	\$ 330.6	\$ 484.3	\$ 3,356.0	\$ 8,691.2	\$ 4,024.2	\$ 5,571.8	\$ 3,691.4	\$ 8,675.9	\$ 9,989.7	\$ 60,057.4
Hoku First Block Revenues	\$ 2,277.5	\$ 2,353.4	\$ 1,498.3	\$ 743.2	\$ 1,238.6	\$ 1,977.8	\$ 2,353.4	\$ 2,277.5	\$ 2,353.4	\$ 2,353.4	\$ 2,201.6	\$ 2,353.4	\$ 23,981.4
Net Power Supply Costs (\$ x 1000)	\$ (1,448.5)	\$ 2,503.0	\$ 11,890.9	\$ 31,075.8	\$ 30,836.4	\$ 15,363.6	\$ 6,416.0	\$ 11,534.4	\$ 13,814.8	\$ 10,786.4	\$ 2,756.4	\$ 374.6	\$ 135,903.8
Purchased Power	29.75	33.24	29.66	44.82	47.43	47.43	40.48	41.08	55.42	30.87	34.92	29.84	43.20
Surplus Sales	27.56	25.51	20.97	28.73	29.88	30.64	39.26	40.93	44.62	31.64	30.03	29.99	31.48

**Idaho Power/102  
Witness: Scott Wright**

**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**

**October 20, 2010**









Mid-Columbia Heavy Load and Light Load Daily Forward Curves  
April 2011 - March 2012

Idaho Power/102  
Wright/6

8/30/2010	34.4	30.7	28	45.8	52.2	48.8	45.7	47.45	53.75	52.2373	49.0095	43.5759
8/31/2010	34.95	31.25	28.55	46.35	52.75	49.35	46.25	48	54.3	52.5207	49.3084	43.9011
9/1/2010	35.05	31.35	28.65	46.45	52.85	49.45	46.35	48.1	54.4	51.9267	48.7411	43.3785
9/2/2010	35.05	31.35	28.65	46.3	52.7	49.3	46.05	47.8	54.1	51.0515	47.8575	42.4808
9/3/2010	34.95	31.25	28.55	46.2	52.6	49.2	45.95	47.7	54	50.7874	47.6033	42.2433
9/7/2010	34.7	31	28.3	45.95	52.35	48.95	45.8	47.55	53.85	50.2736	47.1084	41.7803
9/8/2010	34.7	31	28.3	46.1	52.5	49.1	46.1	47.85	54.15	50.8386	47.6744	42.348
9/9/2010	35.35	31.65	28.95	46.8	53.2	49.8	46.6	48.35	54.65	52.0218	48.8139	43.4139
9/10/2010	35.65	31.95	29.25	47.45	53.85	50.45	47.4	49.15	55.45	52.7154	49.5205	44.1425
9/13/2010	36.1	32.4	29.7	48.1	54.5	51.1	47.95	49.7	56	53.2066	50.0174	44.6489
9/14/2010	35.15	31.45	28.75	47.35	53.75	50.35	47.25	49	55.3	52.7044	49.4907	44.081
9/15/2010	35.05	31.35	28.65	47.2	53.6	50.2	47.1	48.85	55.15	52.9432	49.7017	44.2454
9/16/2010	34.8	31.1	28.4	47.25	53.65	50.25	47.15	48.9	55.2	52.7508	49.5245	44.0935
9/17/2010	33.95	30.25	27.55	46.45	52.85	49.45	45.85	47.6	53.9	51.5881	48.3537	42.9092
9/20/2010	33.35	29.65	26.95	45.65	52.05	48.65	45.1	46.85	53.15	51.5245	48.2565	42.7555
9/21/2010	33.25	29.55	26.85	45.55	51.95	48.55	45	46.75	53.05	49.8738	46.7038	41.3678
9/22/2010	33.2	29.5	26.8	45.35	51.75	48.35	45	46.75	53.05	49.3543	46.2141	40.928
9/23/2010	33.15	29.45	26.75	45.3	51.7	48.3	44.95	46.7	53	49.3979	46.2549	40.9641
9/24/2010	33.1	29.4	26.7	44.65	51.05	47.65	44.6	46.35	52.65	49.4004	46.2303	40.894
9/27/2010	32.5	28.8	26.1	43.85	50.25	46.85	43.85	45.6	51.9	49.2243	46.0279	40.6473
9/28/2010	32.7	29	26.3	44.3	50.7	47.3	44.15	45.9	52.2	49.093	45.9085	40.5481
9/29/2010	32.55	28.85	26.15	44.1	50.5	47.1	43.9	45.65	51.95	48.7833	45.6052	40.2555
9/30/2010	32.1	28.55	25.85	43.7	50.1	46.7	43.65	45.4	51.7	48.0701	44.918	39.6119

Average HL	40.69	36.92	35.21	54.69	59.76	57.11	53.07	55.59	60.30	58.27	55.69	50.69
Max HL	48.16	44.98	43.16	65.09	69.11	67.10	63.57	66.92	70.27	69.61	66.29	62.98
Min HL	32.50	28.80	26.10	43.85	50.25	46.85	43.85	45.60	51.90	48.78	45.61	40.26
Spread	15.66	16.18	17.06	21.24	18.86	20.25	19.72	21.32	18.37	20.82	20.69	22.72









Mid-Columbia Heavy Load and Light Load Daily Forward Curves  
April 2011 - March 2012

Idaho Power/102  
Wright/11

8/27/2010	26.047	17.7645	10.7958	29.9739	35.9028	38.2085	40.3321	41.6993	44.4337	41.9134	40.0221	37.0937
8/30/2010	25.8207	17.7624	10.6688	30.122	36.0802	38.3973	39.8198	41.1696	43.8693	42.0206	39.7164	36.3208
8/31/2010	26.3213	18.3007	11.2402	30.4497	36.4727	38.8149	40.2065	41.5695	44.2953	42.1553	39.9904	36.3822
9/1/2010	26.4313	18.4795	11.4797	30.4784	36.5071	38.8516	40.1505	41.5115	44.2336	41.9124	39.7661	36.3678
9/2/2010	26.146	18.1958	11.5334	30.5206	36.5577	38.9054	39.9817	41.3337	44.0477	41.6136	39.7654	36.3672
9/3/2010	26.2971	18.352	11.6938	30.7428	36.8238	39.1886	40.0632	41.4213	44.1374	41.5793	39.7327	36.0989
9/7/2010	27.3535	18.2923	12.1194	30.7257	36.8033	39.1668	40.1717	41.5335	44.257	41.6504	39.6584	36.3384
9/8/2010	27.3819	18.0264	11.7514	30.8019	36.8946	39.2639	40.4428	41.8138	44.5557	42.3704	39.9962	36.1609
9/9/2010	27.7978	18.1063	11.6066	31.1847	37.3531	39.7519	40.5099	41.8832	44.6296	43.5066	40.7875	37.0795
9/10/2010	28.197	18.2451	12.0681	31.3271	37.5237	39.9335	40.7675	42.1494	44.9133	43.6504	41.1544	37.2581
9/13/2010	28.3694	18.5732	12.3444	31.6024	37.8534	40.2844	40.9577	42.3461	45.1229	43.8598	41.3896	37.4736
9/14/2010	28.2799	17.7825	11.4726	31.1714	37.3372	39.735	40.8873	42.2733	45.0453	44.3283	41.4585	37.4898
9/15/2010	28.1675	18.0708	11.5883	31.4119	37.6253	40.0416	40.9456	42.3336	45.1096	43.4793	40.9217	37.1462
9/16/2010	27.5559	17.8741	11.4005	31.1708	37.3364	39.7342	40.5604	41.9353	44.6852	43.0159	40.8255	37.175
9/17/2010	26.4517	17.52	10.9929	30.8061	36.8996	39.2693	39.8134	41.163	43.8622	42.7851	40.4283	36.5003
9/20/2010	25.7885	16.9435	10.2235	30.4567	36.4811	38.8239	39.7191	41.0656	43.7584	41.1355	39.3496	35.1229
9/21/2010	26.6595	16.6907	10.0258	29.961	35.8874	38.1921	39.4045	40.7403	43.4118	40.5171	38.9201	35.0162
9/22/2010	26.5877	16.6457	9.77153	29.9784	35.9082	38.2143	39.1896	40.5181	43.175	40.5871	38.8763	35.3958
9/23/2010	26.9488	16.9783	10.0844	29.9167	35.8343	38.1356	39.4001	40.7357	43.4069	40.5215	38.7468	35.3158
9/24/2010	26.4177	16.7695	9.76307	29.5805	35.4316	37.707	39.3856	40.7207	43.3909	40.2011	38.5906	35.0716
9/27/2010	25.9068	16.0541	8.98334	29.0008	34.7372	36.9681	39.2591	40.59	43.2516	40.8309	38.1772	34.6791
9/28/2010	26.1497	16.2428	9.67656	28.8613	34.5701	36.7902	39.0163	40.3389	42.9841	40.1644	38.1743	34.9177
9/29/2010	26.1854	15.9696	8.98288	28.7596	34.4483	36.6606	39.2648	40.5958	43.2578	40.3896	38.5537	34.3311
9/30/2010	26.1347	14.7045	9.04892	27.2658	35.005	36.4338	39.4491	40.7864	43.4609	40.3415	38.5361	34.1783

Average LL      31.45      23.92      20.34      35.75      42.81      45.56      46.09      47.65      50.78      49.37      46.53      42.69

Max LL	38.06	29.54	27.30	41.20	49.34	52.51	52.81	54.60	58.85	59.12	56.95	49.90
Min LL	25.79	15.97	8.98	28.76	34.45	36.66	39.01	40.33	42.98	40.16	38.17	34.33
Spread	12.27	13.57	18.31	12.44	14.90	15.85	13.79	14.26	15.88	18.96	18.78	15.57

Idaho Power/103  
Witness: Scott Wright

BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott Wright

Producer Price Index for Electric Power

October 20, 2010

Description: PPI: Electric Power - Total, (Index, 1982=100, NSA)  
Source: Bureau of Labor Statistics: Producer Price Index; Moody's Analytics  
Mnemonic: FXPPIFU4.US  
Native Frequency: QUARTERLY  
Geography: United States

2010 Q1	178.26669
2010 Q2	184.39999
2010 Q3	189.9243
2010 Q4	182.0135
2011 Q1	183.6804
2011 Q2	186.7858
2011 Q3	192.9962
2011 Q4	185.4799
2012 Q1	186.96919
2012 Q2	190.0477
2012 Q3	195.94769
2012 Q4	187.8188
2013 Q1	189.15221
2013 Q2	192.2061
2013 Q3	198.14481
2013 Q4	190.0515
2014 Q1	191.3688
2014 Q2	194.4361
2014 Q3	200.4299
2014 Q4	192.2823
2015 Q1	193.6387
2015 Q2	196.7428
2015 Q3	202.8018
2015 Q4	194.5528
2016 Q1	195.9575
2016 Q2	199.09109
2016 Q3	205.2225
2016 Q4	196.89
2017 Q1	198.2968
2017 Q2	201.491
2017 Q3	207.6834
2017 Q4	199.28481
2018 Q1	200.7197
2018 Q2	203.9355
2018 Q3	210.2009
2018 Q4	201.7178
2019 Q1	203.1635
2019 Q2	206.42081
2019 Q3	212.7424
2019 Q4	204.1813
2020 Q1	205.6376
2020 Q2	208.9326
2020 Q3	215.33009
2020 Q4	206.6687

Idaho Power/104  
Witness: Scott Wright

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**IDAHO POWER COMPANY**

Exhibit Accompanying Testimony of Scott Wright

**Idaho Power Company's Forward Price Curves Discounted for Inflation  
Used to Re-Price Purchased Power  
and Surplus Sales for the October Update**

October 20, 2010



Idaho Power/105  
Witness: Scott Wright

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, 2011 – March 31, 2012  
(Multiple Gas Prices – 82 Years of Hydro)

October 20, 2010



Idaho Power/106  
Witness: Scott Wright

BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott Wright

Idaho Power Company's Rate Spread for October APCU Update

October 20, 2010



Idaho Power/107  
Witness: Scott Wright

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**IDAHO POWER COMPANY**

Exhibit Accompanying Testimony of Scott Wright

Idaho Power Company's Current Billed Revenue to  
Proposed Billed Revenue

October 20, 2010

**Idaho Power Company**  
**Calculation of Revenue Impact**  
**State of Oregon**  
**2011 APCU October Update 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
<b><u>Uniform Tariff Rates:</u></b>										
1	Residential Service	1	13,593	203,409,104	\$16,196,916	79.63	\$456,654	\$16,653,570	81.87	2.82%
2	Small General Service	7	2,474	17,312,084	\$1,559,291	90.07	\$39,194	\$1,598,485	92.33	2.51%
3	Large General Service	9	913	133,660,614	\$8,330,392	62.32	\$299,132	\$8,629,524	64.56	3.59%
4	Dusk to Dawn Lighting	15	0	484,216	\$112,548	232.43	\$0	\$112,548	232.43	0.00%
5	Large Power Service	19	7	256,052,181	\$11,933,367	46.61	\$534,129	\$12,467,496	48.69	4.48%
6	Agricultural Irrigation Service	24	1,584	66,179,096	\$5,093,752	76.97	\$283,115	\$5,376,867	81.25	5.56%
7	Unmetered General Service	40	3	12,858	\$996	77.43	\$27	\$1,023	79.53	2.71%
8	Street Lighting	41	14	770,982	\$127,784	165.74	\$1,436	\$129,220	167.60	1.12%
9	Traffic Control Lighting	42	6	16,726	\$1,319	78.84	\$57	\$1,376	82.25	4.32%
10	Total Uniform Tariffs		18,594	677,897,861	43,356,364	63.96	\$1,613,744.00	44,970,108	66.34	3.72%
12	Total Oregon Retail Sales		18,594	677,897,861	43,356,364	63.96	\$1,613,744.00	44,970,108	66.34	3.72%

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