



# Oregon

Kate Brown, Governor

## Public Utility Commission

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February 12, 2016

### ***Via Electronic Filing***

OREGON PUBLIC UTILITY COMMISSION  
ATTENTION: FILING CENTER  
PO BOX: 1088  
SALEM OR 97308-1088

**RE: Docket No. UE 301 – In the Matter of  
IDAHO POWER COMPANY's  
2016 Annual Power Cost Update (APCU)**

Enclosed for electronic filing is Staff Opening Testimony.

*/s/ Mark Brown*

Mark Brown

Utility Program

Filing on Behalf of Public Utility Commission Staff

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**PUBLIC UTILITY COMMISSION  
OF OREGON**

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**UE 301**

**STAFF OPENING TESTIMONY OF**

**SCOTT GIBBENS**

**In the Matter of  
IDAHO POWER COMPANY's  
2016 Annual Power Cost Update (APCU)**

**February 12, 2016**

CASE: UE 301  
WITNESS: SCOTT GIBBENS

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 100**

**Opening Testimony**

**February 12, 2016**

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

2 A. My name is Scott Gibbens. I am a Utility Analyst for the Public Utility  
3 Commission of Oregon. My business address is 201 High St. SE Ste. 100  
4 Salem, Oregon 97301.

5 **Q. Please describe your educational background and work experience.**

6 A. My Witness Qualification Statement is found in Exhibit Staff/101.

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

8 A. The purpose of my testimony is to present Staff's analysis and concerns  
9 regarding the 2016 October Update, the first portion of Idaho Power  
10 Company's (IPC or Company) Annual Power Cost Update (APCU).

11 **Q. How is your testimony organized?**

12 A. My testimony is organized as follows:

13	Filing, Compliance and Model Changes .....	1
14	Issues .....	4

15 Filing, Compliance and Model Changes

16 **Q. Did the filing conform to applicable rules and orders?**

17 A. Yes, the filing follows all of the applicable rules and orders. Commission Order  
18 No. 08-238 (Order) contains the majority of rules and stipulations regarding the  
19 APCU October Update. The Order requires IPC to utilize the AURORA model  
20 to determine the estimated net power supply expense and reprice the  
21 wholesale electric prices. In addition, the Order stipulates inputs to be updated  
22 annually, which will be discussed in the following section.

1 **Q. Please describe what inputs the Company updated.**

2 A. Per the Order, the Company updated the following inputs:

3 a. Fueling prices and transportation costs;

4 b. Planned outages and forced outage rates;

5 c. Heat rates;

6 d. Forecast of Normalized Load and Normalized Sales;

7 e. Contracts for wholesale power and power purchases and sales;

8 f. Forward price curve;

9 g. PURPA contract expenses; and

10 h. The Oregon state allocation factor.

11 IPC did not update wheeling expenses from the previous filing as there was no  
12 update submitted by the Company's transmission planning group due to the  
13 fact that wheeling expenses had not changed since the previous filing.

14 **Q. Did Staff check the validity and reasonableness of the updated input  
15 parameters?**

16 A. Yes, Staff reviewed every updated input used in the October Update. In  
17 general, the values seem reasonable and in line with both previous filings and  
18 last year's actual parameter values. Staff currently has pending several Data  
19 Requests that are intended to clarify a few outliers. Potential issues associated  
20 with input parameters are discussed later in my testimony.

21 **Q. Did IPC perform the prescribed calculations properly?**

1 A. Yes, Staff has found no errors associated with the calculations used in the  
2 APCU. Company adhered to all pertinent Commission orders in every  
3 calculation.

4

5 **Q. How does this projection compare with last year's actual parameter**  
6 **values?**

7 A. Historically, the 2015 calendar year was a poor hydro year. The hydro power  
8 generated was approximately 30 percent lower than the mean of the previous  
9 87 years. This resulted in higher generation costs among coal, natural gas and  
10 purchased power. The total "net power supply expense" NPSE for the calendar  
11 year was \$388,073,000. The October Update predicts an April-March NPSE of  
12 \$352,028,000. Staff believes that the ten percent discrepancy between these  
13 two numbers is warranted given the nature of the hydro year.

14 **Q. Did the Company propose any modeling changes in the APCU?**

15 A. Yes, there was one major change to the model. The Company adjusted the  
16 manner in which it portrays operations and maintenance (O&M) costs. These  
17 costs are associated with oil, handling, administrative and general expenses  
18 (OHAG) and do not vary with the amount of power generated by the plant. As  
19 such, IPC removed these costs from the AURORA model and added them  
20 back as a fixed cost after the model was run. This resulted in a change to the  
21 "per unit" costs of coal fired plants, notably Valmy. The results of last year's  
22 and this year's APCU modeling remain similar. Staff finds that NPSE are

1 projected to rise approximately 3.5 percent. This year's update estimated a  
2 decrease in coal-generated power of approximately 35 percent.

3  
4 **Q. What impact on NPSE does the model change to O&M have, according**  
5 **to the Company?**

6 A. Including O&M expenses outside of the AURORA model will more closely align  
7 the projection with the actual decisions made by IPC's dispatching department.  
8 The change will ensure that these costs are recovered regardless of the  
9 amount of generation by a plant.

10 Issues

11 **Q. What issues does Staff have in regards to the change to modeling O&M**  
12 **costs in AURORA?**

13 A. In principal, Staff agrees that fixed costs modeled as variable costs will result in  
14 misallocations and inefficiencies. However, Staff still has concerns with the  
15 stated reasons and results of the model change.

16 **Q. Do you agree that the main driver of the increase in per-unit cost at**  
17 **Valmy is the change in OHAG expense modeling?**

18 A. No, Idaho Power/100, Noe/8 at lines 9 through 11 states that the "change in  
19 modeling and recovery of OHAG expenses (is) the main driver of the increase  
20 in per-unit cost at Valmy." This is not correct. The increase in per unit costs is  
21 due to a decrease in annual energy from 2015 to 2016. However, had OHAG  
22 remained as a variable cost in the modeling, annual energy would have

1 decreased even more (See Table 1 below.) Staff is continuing to investigate  
2 the appropriate modeling treatment of OHAG.

3 **Table 1**

	Valmy Power Cost	
	Energy (MWh)	Cost in 1000
2015 Filing <sup>1</sup>	470,994.4	\$ 16,721
2016 OHAG As Variable <sup>2</sup>	89,377.5	3,450
2016 OHAG As Fixed <sup>3</sup>	276,332.7	13,037

4 **Q. Does Staff have further questions regarding O&M costs?**

5 A. Yes. Staff found that the Boardman plant O&M was over 9,000 times smaller  
6 than either of IPC's other two coal plants. In response to Staff's stated issues,  
7 IPC responded that this was due to IPC having minority ownership in the plant,  
8 and thus contributing less to O&M costs. However, Staff does not believe that  
9 the relative difference in ownership among plants is sufficient to explain the  
10 discrepancy between O&M at the Boardman plant as compared to IPC's two  
11 other plants. Staff continues to investigate this discrepancy.

12 **Q. What issue does Staff have with regard to contract costs?**

13 A. Staff requested information regarding the projected PURPA contract costs for  
14 calendar years 2015 and 2016. Staff has further questions following IPC's  
15 confidential response to its data request.

16 **Q. Is Staff investigating any other issues?**

17 A. Yes. Staff believes FERC account 501, related to recovery under the power  
18 cost adjustment mechanism, includes some component of labor costs. Staff is

<sup>1</sup> Exhibit Staff/102

<sup>2</sup> Exhibit Staff/103

<sup>3</sup> Exhibit Idaho Power/101



1           investigating whether these costs are appropriately included in the power cost  
2           calculations. These accounts also include certain fixed costs related to  
3           depreciation. Staff is investigating whether these costs are appropriately  
4           included in the power cost calculations.

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

6       A. Yes.

CASE: UE 301  
WITNESS: SCOTT GIBBENS

**PUBLIC UTILITY COMMISSION  
OF  
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**STAFF EXHIBIT 101**

**Witness Qualification Statement**

**February 12, 2016**

WITNESS QUALIFICATION STATEMENT

NAME: Scott Gibbens

EMPLOYER: Public Utility Commission Of Oregon

TITLE: Utility Analyst  
Energy Rates, Finance and Audit

ADDRESS: 201 High St. SE Ste. 100  
Salem, OR 97301-3612

EDUCATION: Bachelor of Science, Economics, University of Oregon  
Masters of Science, Economics, University of Oregon

EXPERIENCE: I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I also handle analysis and decision making of affiliated interest and property sale filings. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, new product design, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

CASE: UE 301  
WITNESS: SCOTT GIBBENS

**PUBLIC UTILITY COMMISSION  
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**STAFF EXHIBIT 102**

**Exhibits in Support of  
Opening Testimony**

**February 12, 2016**



CASE: UE 301  
WITNESS: SCOTT GIBBENS

**PUBLIC UTILITY COMMISSION  
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**STAFF EXHIBIT 103**

**Exhibits in Support of  
Opening Testimony**

**February 12, 2016**

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2014 -- MARCH 31, 2015 (Multiple Gas Prices/85 Years of Hydro Conditions)  
Repriced Using UE 195 Settlement Methodology - October Update  
AVERAGE

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	852,208.0	935,956.8	894,784.8	676,572.5	507,298.0	540,092.4	551,497.9	468,580.3	673,213.8	753,542.0	825,731.1	844,213.0	8,523,690.7
Bridge													
Energy (MWh)	208,161.3	280,964.7	283,378.6	473,492.8	484,176.6	458,325.8	482,786.1	467,109.2	485,075.4	454,980.0	382,781.3	380,627.4	4,841,859.1
Expense (\$ x 1000)	\$ 4,931.7	\$ 6,608.2	\$ 6,633.2	\$ 10,753.3	\$ 10,976.0	\$ 10,416.8	\$ 10,950.7	\$ 10,595.9	\$ 10,991.8	\$ 10,035.9	\$ 8,481.4	\$ 8,420.3	\$ 109,795.1
Boardman													
Energy (MWh)	1,737.5	2,968.6	11,159.6	31,566.2	34,821.6	29,852.6	34,457.6	30,903.5	35,111.3	20,094.6	13,229.9	17,833.1	263,736.0
Expense (\$ x 1000)	\$ 47.9	\$ 81.2	\$ 311.9	\$ 819.9	\$ 896.4	\$ 777.1	\$ 896.8	\$ 803.3	\$ 904.1	\$ 586.9	\$ 393.5	\$ 526.2	\$ 7,035.3
Valmy													
Energy (MWh)	5,067.0	7,748.4	4,627.7	57,130.9	68,926.2	39,944.9	61,583.0	59,772.2	90,612.8	34,308.1	17,888.1	23,385.1	470,994.4
Expense (\$ x 1000)	\$ 183.9	\$ 283.7	\$ 167.7	\$ 2,002.5	\$ 2,409.0	\$ 1,398.8	\$ 2,150.7	\$ 2,097.1	\$ 3,136.6	\$ 1,309.8	\$ 684.2	\$ 896.9	\$ 16,721.0
Langley Gulch													
Energy (MWh)	13,371.3	31,445.7	15,778.1	128,009.0	140,533.7	116,327.9	127,126.8	71,121.9	116,343.6	34,883.9	14,312.2	29,776.8	839,031.0
Expense (\$ x 1000)	\$ 437.0	\$ 963.9	\$ 491.5	\$ 3,757.9	\$ 4,198.7	\$ 3,461.5	\$ 3,855.6	\$ 2,376.9	\$ 4,180.3	\$ 1,308.4	\$ 549.2	\$ 1,097.1	\$ 26,678.0
Danskin													
Energy (MWh)	1.8	0.3	29.1	1,545.7	1,115.6	351.8	204.2	10.8	17.5	22.6	1.2	3.2	3,303.8
Expense (\$ x 1000)	\$ 0.1	\$ 0.0	\$ 1.5	\$ 74.0	\$ 53.1	\$ 17.9	\$ 10.1	\$ 0.6	\$ 1.0	\$ 1.4	\$ 0.1	\$ 0.2	\$ 159.9
Bennett Mountain													
Energy (MWh)	-	-	2.8	167.2	158.9	95.1	4.7	-	0.5	0.1	-	-	428.3
Expense (\$ x 1000)	\$ -	\$ -	\$ 0.1	\$ 7.8	\$ 8.0	\$ 5.0	\$ 0.2	\$ -	\$ 0.0	\$ 0.0	\$ -	\$ -	\$ 21.3
Fixed Capacity Charge - Gas Transportation (\$ x 1000)	\$ 737.7	\$ 761.7	\$ 746.7	\$ 780.3	\$ 780.3	\$ 755.7	\$ 761.7	\$ 737.7	\$ 761.7	\$ 761.7	\$ 689.6	\$ 761.7	\$ 9,036.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	3,141.3	11,955.1	96,932.1	184,027.2	173,842.9	23,530.6	45.5	4,432.5	6,564.5	31,744.4	1,774.0	1,047.2	539,037.2
Elkhorn Wind Energy (MWh)	20,502.0	18,304.0	22,117.6	31,551.7	24,405.1	19,545.2	19,382.1	32,298.0	26,193.4	33,933.8	24,180.5	38,239.2	310,652.6
Neal Hot Springs Energy (MWh)	15,867.9	16,396.9	15,867.9	15,867.9	16,396.9	15,867.9	16,396.9	15,867.9	16,396.9	7,825.8	14,810.1	16,396.9	183,959.8
Raft River Geothermal Energy (MWh)	5,360.0	5,316.0	5,323.0	5,726.0	5,998.0	6,111.0	7,004.0	6,939.0	7,199.0	7,056.0	6,662.0	5,674.0	74,367.9
Total Energy Excl. CSPP (MWh)	44,871.2	51,972.0	140,240.6	237,172.8	220,642.8	65,054.7	42,828.5	59,537.4	56,353.8	80,559.9	47,426.6	61,357.3	1,108,017.5
Market Expense (\$ x 1000)	\$ 106.4	\$ 389.6	\$ 3,061.3	\$ 7,397.8	\$ 6,785.5	\$ 1,009.2	\$ 1.7	\$ 198.3	\$ 271.1	\$ 1,289.0	\$ 61.7	\$ 43.5	\$ 20,615.0
Elkhorn Wind Expense (\$ x 1000)	\$ 835.8	\$ 746.2	\$ 1,226.8	\$ 2,100.1	\$ 1,624.4	\$ 1,084.1	\$ 1,075.1	\$ 2,149.8	\$ 1,743.5	\$ 1,938.7	\$ 1,381.5	\$ 1,605.7	\$ 17,511.7
Neal Hot Springs Expense (\$ x 1000)	\$ 1,195.5	\$ 1,235.3	\$ 1,630.9	\$ 1,957.1	\$ 2,022.3	\$ 1,630.9	\$ 1,685.3	\$ 1,957.1	\$ 2,022.3	\$ 835.7	\$ 1,581.6	\$ 1,283.5	\$ 19,037.4
Raft River Geothermal Expense (\$ x 1000)	\$ 239.2	\$ 237.2	\$ 323.2	\$ 417.2	\$ 437.0	\$ 371.1	\$ 425.3	\$ 505.6	\$ 524.5	\$ 437.5	\$ 413.0	\$ 258.6	\$ 4,589.5
Total Expense Excl. CSPP (\$ x 1000)	\$ 2,376.9	\$ 2,608.4	\$ 6,242.2	\$ 11,872.2	\$ 10,869.3	\$ 4,095.3	\$ 3,187.3	\$ 4,810.8	\$ 4,561.4	\$ 4,500.9	\$ 3,437.8	\$ 3,191.3	\$ 61,753.7
Surplus Sales													
Energy (MWh)	292,939.0	300,214.9	125,544.1	47,732.4	26,775.1	150,639.2	404,347.8	207,150.9	200,423.5	145,291.3	349,247.7	416,156.4	2,666,462.4
Revenue including Transmission Expenses (\$ x 1000)	\$ 6,969.8	\$ 6,665.6	\$ 2,315.2	\$ 1,187.3	\$ 763.6	\$ 4,163.9	\$ 13,536.7	\$ 6,500.3	\$ 7,063.0	\$ 3,949.6	\$ 9,939.2	\$ 12,066.0	\$ 75,125.2
Transmission Expenses (\$ x 1000)	\$ 292.9	\$ 300.2	\$ 125.5	\$ 47.7	\$ 26.8	\$ 150.6	\$ 404.3	\$ 207.2	\$ 200.4	\$ 145.3	\$ 349.2	\$ 416.2	\$ 2,666.5
Revenue Excluding Transmission Expenses (\$ x 1000)	\$ 6,676.9	\$ 6,365.3	\$ 2,189.7	\$ 1,139.6	\$ 736.8	\$ 4,013.3	\$ 13,132.3	\$ 6,293.2	\$ 6,862.5	\$ 3,804.3	\$ 9,590.0	\$ 11,649.8	\$ 72,458.7
Net Power Supply Expenses (\$ x 1000)	\$ 2,038.2	\$ 4,941.6	\$ 12,405.1	\$ 28,928.3	\$ 29,453.9	\$ 16,909.8	\$ 8,670.9	\$ 15,129.1	\$ 17,674.4	\$ 14,700.8	\$ 4,645.7	\$ 3,243.9	\$ 158,741.8