Oregon
Kate Brown, Governor

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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
(503) 378-8287

Email: mark.brown@state.or.us

PUBLIC UTILITY COMMISSION
OF OREGON

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

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

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

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

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

Q. How is your testimony organized?

A. My testimony is organized as follows:

Filing, Compliance and Model Changes

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

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

Q. Please describe what inputs the Company updated.

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

a. Fueling prices and transportation costs;

b. Planned outages and forced outage rates;

c. Heat rates;

d. Forecast of Normalized Load and Normalized Sales;

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

f. Forward price curve;

g. PURPA contract expenses; and

h. The Oregon state allocation factor.

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

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

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

Q. Did IPC perform the prescribed calculations properly?

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

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

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

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

A. Yes, there was one major change to the model. The Company adjusted the manner in which it portrays operations and maintenance (O&M) costs. These costs are associated with oil, handling, administrative and general expenses (OHAG) and do not vary with the amount of power generated by the plant. As such, IPC removed these costs from the AURORA model and added them back as a fixed cost after the model was run. This resulted in a change to the "per unit" costs of coal fired plants, notably Valmy. The results of last year's and this year's APCU modeling remain similar. Staff finds that NPSE are projected to rise approximately 3.5 percent. This year's update estimated a decrease in coal-generated power of approximately 35 percent.

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

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

Issues

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

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

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

A. No, Idaho Power/100, Noe/8 at lines 9 through 11 states that the "change in modeling and recovery of OHAG expenses (is) the main driver of the increase in per-unit cost at Valmy." This is not correct. The increase in per unit costs is due to a decrease in annual energy from 2015 to 2016. However, had OHAG remained as a variable cost in the modeling, annual energy would have decreased even more (See Table 1 below.) Staff is continuing to investigate the appropriate modeling treatment of OHAG.

Table 1

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

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

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

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

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

Q. Is Staff investigating any other issues?

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

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[1] Exhibit Staff/102
[2] Exhibit Staff/103
[3] Exhibit Idaho Power/101

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

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 301
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

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

Attachment 4 - Response to Staff's DR 18

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2016 -- MARCH 31, 2017 (Multiple Gas Prices/87 Years of Hydro Conditions)
Repriced Using UE 195 Settlement Methodology - October Update
AVERAGE (Valmy O&M at $4.99/MWh)

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	888,455.5	951,621.3	924,383.1	702,795.2	481,419.4	564,230.3	545,380.9	459,686.3	681,232.3	760,998.6	839,928.9	861,306.0	8,661,437.9
Bridger													
Energy (MWh)	63,612.2	53,460.2	125,609.3	325,040.2	321,079.6	167,098.7	133,579.2	243,572.9	304,961.3	248,551.8	188,684.4	206,821.0	2,382,070.8
Expense ($ x 1000)	$ 1,869.7	$ 1,571.1	$ 3,636.0	$ 9,279.1	$ 9,167.5	$ 4,808.4	$ 3,884.8	$ 7,006.9	$ 8,670.4	$ 7,073.2	$ 5,355.8	$ 5,890.8	$ 68,213.7
Boardman													
Energy (MWh)	4,326.8	3,597.6	14,532.6	32,220.7	32,889.8	23,901.8	20,520.4	26,073.3	30,506.7	12,401.1	9,832.5	9,633.2	220,436.5
Expense ($ x 1000)	$ 118.4	$ 99.4	$ 394.1	$ 854.9	$ 873.3	$ 641.2	$ 554.9	$ 698.5	$ 810.3	$ 374.1	$ 295.9	$ 293.4	$ 6,008.4
Valmy													
Energy (MWh)	373.8	499.8	2,553.2	22,674.5	13,536.3	9,636.0	5,384.1	8,434.3	13,907.1	4,769.5	5,353.6	2,255.3	89,377.5
Expense ($ x 1000)	$ 15.2	$ 20.6	$ 101.6	$ 857.7	$ 513.0	$ 366.0	$ 211.6	$ 335.5	$ 534.2	$ 190.6	$ 211.8	$ 92.3	$ 3,450.2
Langley Gulch													
Energy (MWh)	163,028.8	163,323.9	183,149.9	198,263.9	198,475.3	192,000.0	195,874.9	171,344.1	174,476.3	162,087.6	149,487.7	170,479.9	2,121,992.4
Expense ($ x 1000)	$ 2,868.0	$ 2,748.1	$ 3,113.4	$ 3,370.8	$ 3,503.7	$ 3,360.3	$ 3,477.9	$ 3,727.1	$ 4,240.3	$ 3,863.2	$ 3,347.7	$ 3,740.8	$ 41,361.2
Danskin													
Energy (MWh)	2,091.0	1,845.4	16,023.6	74,918.4	68,511.1	39,459.4	27,739.9	11,375.7	5,453.0	1,687.3	2,568.5	928.8	252,602.0
Expense ($ x 1000)	$ 39.4	$ 37.0	$ 379.9	$ 1,980.2	$ 1,803.5	$ 979.0	$ 627.4	$ 271.8	$ 136.1	$ 43.6	$ 66.6	$ 22.7	$ 6,387.1
Bennett Mountain													
Energy (MWh)	265.7	106.9	5,237.6	46,847.0	37,722.3	17,150.4	11,737.9	4,905.2	1,718.3	190.3	253.2	33.3	126,168.1
Expense ($ x 1000)	$ 4.8	$ 2.1	$ 116.6	$ 1,205.9	$ 950.9	$ 392.1	$ 246.7	$ 108.9	$ 41.0	$ 4.5	$ 6.0	$ 0.9	$ 3,080.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 735.4	$ 759.4	$ 744.4	$ 778.0	$ 778.0	$ 753.4	$ 759.4	$ 735.4	$ 759.4	$ 759.4	$ 687.3	$ 759.4	$ 9,008.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	3,499.7	7,902.8	25,516.0	98,256.2	99,840.6	48,885.9	13,291.4	57,318.8	20,546.8	43,079.6	3,382.7	5,909.0	427,429.5
Elkhorn Wind Energy (MWh)	25,790.0	24,592.0	24,055.4	26,880.8	24,330.6	20,734.6	21,842.2	29,820.2	29,732.8	24,269.2	24,158.8	28,532.8	304,739.1
Neal Hot Springs Energy (MWh)	14,424.2	10,940.5	11,065.3	7,822.4	9,924.6	11,286.0	12,896.6	16,671.7	17,970.0	18,765.7	16,385.0	16,782.0	164,934.1
Raft River Geothermal Energy (MWh)	6,213.3	5,111.2	5,097.5	5,661.1	5,734.4	5,757.2	7,594.7	6,634.5	6,897.6	6,890.5	6,324.0	6,504.2	74,420.3
Total Energy Excl. CSPP (MWh)	49,927.2	48,546.5	65,734.2	138,620.5	139,830.2	86,663.6	55,624.9	110,445.2	75,147.1	93,005.0	50,250.5	57,728.0	971,522.9
Market Expense ($ x 1000)	$ 86.0	$ 177.9	$ 549.1	$ 3,016.6	$ 3,448.1	$ 1,615.3	$ 420.4	$ 1,947.0	$ 754.1	$ 1,549.0	$ 116.8	$ 185.0	$ 13,865.3
Elkhorn Wind Expense ($ x 1000)	$ 1,115.4	$ 1,063.6	$ 1,415.7	$ 1,898.1	$ 1,718.0	$ 1,220.2	$ 1,285.4	$ 2,105.6	$ 2,099.4	$ 1,471.0	$ 1,464.3	$ 1,271.1	$ 18,127.7
Neal Hot Springs Expense ($ x 1000)	$ 1,155.2	$ 876.2	$ 1,209.1	$ 1,025.7	$ 1,301.3	$ 1,233.2	$ 1,409.2	$ 2,186.0	$ 2,356.2	$ 2,098.6	$ 1,832.3	$ 1,375.6	$ 18,058.7
Raft River Geothermal Expense ($ x 1000)	$ 289.1	$ 237.8	$ 322.7	$ 430.0	$ 435.6	$ 364.4	$ 480.7	$ 504.0	$ 523.9	$ 445.3	$ 408.7	$ 309.0	$ 4,751.3
Total Expense Excl. CSPP ($ x 1000)	$ 2,645.8	$ 2,355.5	$ 3,496.5	$ 6,370.3	$ 6,903.0	$ 4,433.2	$ 3,595.8	$ 6,742.6	$ 5,733.7	$ 5,563.9	$ 3,822.1	$ 3,140.7	$ 54,803.0
Surplus Sales													
Energy (MWh)	378,144.3	280,564.8	212,690.7	32,845.6	23,189.7	43,732.4	149,169.0	46,618.0	123,700.2	119,143.0	294,495.0	380,766.1	2,085,058.7
Revenue Including Transmission Costs ($ x 1000)	$ 8,427.4	$ 5,724.2	$ 4,149.0	$ 914.2	$ 726.2	$ 1,310.3	$ 4,278.7	$ 1,436.1	$ 4,117.2	$ 3,885.2	$ 9,222.0	$ 10,809.7	$ 55,000.2
Transmission Costs ($ x 1000)	$ 378.1	$ 280.6	$ 212.7	$ 32.8	$ 23.2	$ 43.7	$ 149.2	$ 46.6	$ 123.7	$ 119.1	$ 294.5	$ 380.8	$ 2,085.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 8,049.3	$ 5,443.6	$ 3,936.3	$ 881.4	$ 703.0	$ 1,266.6	$ 4,129.5	$ 1,389.5	$ 3,993.5	$ 3,766.0	$ 8,927.5	$ 10,428.9	$ 52,915.1
Net Power Supply Expenses ($ x 1000)	$ 247.3	$ 2,149.5	$ 8,046.3	$ 23,815.6	$ 23,789.8	$ 14,467.0	$ 9,228.9	$ 18,237.3	$ 16,931.9	$ 14,106.5	$ 4,865.7	$ 3,512.0	**$ 139,397.8**
PURPA ($ x 1000)	$16,759.31	$18,807.64	$21,649.88	$23,505.36	$21,062.57	$18,736.52	$16,919.82	$15,975.03	$15,565.85	$12,045.69	$14,314.33	$13,551.38	$ 208,893.4
Total Net Power Supply Expenses ($ x 1000)	$ 17,006.6	$ 20,957.1	$ 29,696.1	$ 47,320.9	$ 44,852.4	$ 33,203.5	$ 26,148.8	$ 34,212.3	$ 32,497.8	$ 26,152.2	$ 19,180.0	$ 17,063.4	**$ 348,291.2**
Sales at Customer Level (In 000s MWH)	1,028.406	1,049.929	1,230.508	1,474.064	1,554.059	1,387.063	1,110.593	1,032.641	1,153.609	1,277.132	1,213.385	1,105.482	14,616.871
Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
Unit Cost / MWH (for PCAM)	$16.54	$19.96	$24.13	$32.10	$28.86	$23.94	$23.54	$33.13	$28.17	$20.48	$15.81	$15.44	**$23.83**
Prices Used in Purchased Power & Surplus Sales Above:													
Heavy Load													
Portion of Purchased Power considered HL I	**64.25%**	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	
Purchased Power HL Price	27.21	26.23	25.59	35.21	38.40	36.31	32.96	35.53	38.53	37.85	36.41	32.82	
Portion of Surplus Sales considered HL Surp	**62.70%**	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	
Surplus Sales HL Price	25.24	24.33	23.75	32.67	35.63	33.69	30.58	32.97	35.74	35.11	33.78	30.45	
Light Load													
Portion of Purchased Power considered LL F	**35.75%**	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	
Purchased Power LL Price	19.86	15.82	14.20	22.59	27.59	27.17	29.23	31.16	33.42	32.57	31.16	28.59	
Portion of Surplus Sales considered LL Surp	**37.30%**	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	
Surplus Sales LL Price	17.32	13.79	12.38	19.70	24.06	23.69	25.49	27.17	29.15	28.40	27.17	24.93	

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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
Bridger													
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	$ 886.8	$ 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	-	-	429.3
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	$ 4,168.9	$ 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	$ 4,018.3	$ 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