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May 6, 2014

VIA ELECTRONIC AND U.S. MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

Re: UE 279 In The Matter of IDAHO POWER COMPANY's 2014 Annual Power Cost Update

Attention Filing Center:

Enclosed for filing in the above-referenced matter is an original and five copies of Exhibit 1 to the Joint Explanatory Brief which was originally filed on April 21, 2014. We are making this filing on behalf of the Stipulating Parties pursuant to Administrative Law Judge Patrick Power's May 1, 2014, Ruling.

A copy of this filing has been served on all parties to this proceeding. Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Enclosures
cc: Service List

Exhibit 1

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 279

Stipulating Parties

Exhibit Accompanying Joint Explanatory Brief

Impact of Lower Natural Gas Prices on Idaho Power's Net Power Supply Expense.

May 2014

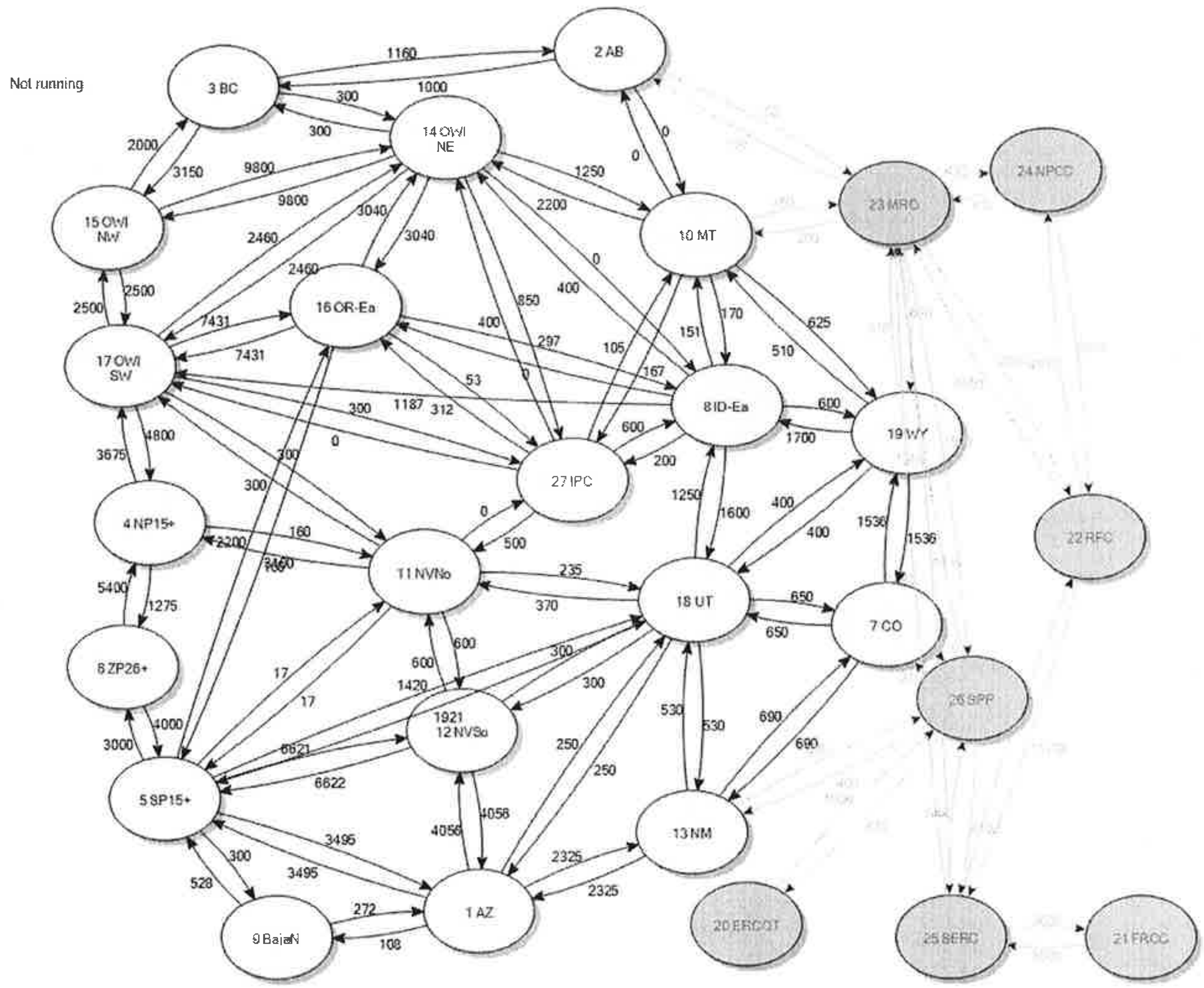
Exhibit 1

Impact of Lower Natural Gas Prices on Idaho Power's Net Power Supply Expense

The October Update involves a determination of Idaho Power's net power supply expense (NPSE) using a normal water scenario. In other words, the NPSE determination in the October Update is based on an expectation that hydro generation will be at a level reflective of the historical average over the past 85 years. Under a normal hydro production scenario, Idaho Power is an annual net exporter of energy. Because the price of natural gas is closely correlated to the modeled market energy prices in the Pacific Northwest, a reduction in the price of natural gas results in lower market energy prices. Lower market energy prices in turn drive down the revenue generated by surplus sales for Idaho Power, resulting in higher NPSE.

The Company uses the AURORA model to calculate its NPSE. AURORA is a market forecasting model that calculates the Company's NPSE using a simulation of the entire Western Electricity Coordinating Council ("WECC") footprint. Figure 1 below shows how AURORA is divided up into multiple areas, with each area having resources and demand and inter-connecting transmission links.

<u>Figure 1</u>



When an AURORA simulation is run, the demand in each area is served with the least cost resources in that area or from market purchases from a nearby area. In order to determine least cost resources, the AURORA model develops a resource stack for each area, dispatching the least cost resources until demand is met. Based on current resource expenses, natural gas resources are typically more expensive than hydro and coal generation; therefore, natural gas resources become the marginal resource that sets the market price for that area. When a natural gas price is modified in AURORA, as occurred in this case when Idaho Power corrected the error, the modified gas price will in turn change the dispatch of all resources in that area based on the new marginal resource expense, *i.e.*, the new natural gas resource expense.

Figure 2 below demonstrate the impact of the lower natural gas price by comparing the Company's original Exhibit 105 (with the $4.32 per MMBtu price) to the new Exhibit 105 that accompanying the February 5, 2014, Partial Stipulation (with the $4.08 per MMBtu price). As shown below, when the natural gas price is changed all of the individual generation numbers for resources, purchases, and sales also change due to the re-dispatch of resources using the different natural gas price. However, the difference in the total generation (excluding PURPA) between the two exhibits is exactly the difference in surplus sales of 200,603.9 megawatt hours ("MWh"). In other words, the net impact of the lower natural gas price is a reduction in the Company's surplus sales. Because surplus sales generate revenue that offsets the Company's power supply expenses, the lower surplus sales results in an increased per unit NPSE of $0.02 per MWh.

Figure 2

October Update Comparison

	Original Filing	Revised Filing	Difference
Hydroelectric Generation (MWh)	8,523,690.7	8,508,188.3	(15,502.4)
Bridger			
Energy (MWh)	4,841,859.1	4,687,214.6	(154,644.5)
Expense ($ x 1000)	$ 109,795.1	$ 106,408.4	$ (3,386.7)
Boardman			
Energy (MWh)	263,736.0	248,874.0	(14,862.0)
Expense ($ x 1000)	$ 7,035.3	$ 6,646.3	$ (389.0)
Valmy			
Energy (MWh)	470,994.4	355,207.3	(115,787.1)
Expense ($ x 1000)	$ 16,721.0	$ 12,638.5	$ (4,082.5)
Langley Gulch			
Energy (MWh)	839,031.0	881,756.9	42,726.0
Expense ($ x 1000)	$ 26,678.0	$ 26,578.9	$ (99.1)
Danskin			
Energy (MWh)	3,303.8	4,677.0	1,373.2
Expense ($ x 1000)	$ 159.9	$ 208.0	$ 48.1
Bennett Mountain			
Energy (MWh)	429.3	608.4	179.1
Expense ($ x 1000)	$ 21.3	$ 26.6	$ 5.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 9,036.3	$ 9,036.3	$ -
Purchased Power (Excluding CSPP)			
Market Energy (MWh)	539,037.2	594,951.1	55,913.9
Elkhorn Wind Energy (MWh)	310,652.6	310,652.6	(0.0)

Neal Hot Springs Energy (MWh)	183,959.8	183,959.8	-
Raft River Geothermal Energy (MWh)	74,367.9	74,367.9	(0.0)
Total Energy Excl. CSPP (MWh)	1,108,017.5	1,163,931.4	55,913.9
Market Expense ($ x 1000)	$ 19,658.7	$ 21,667.3	$ 2,008.6
Elkhorn Wind Expense ($ x 1000)	$ 17,511.7	$ 17,511.7	$ (0.0)
Neal Hot Springs Expense ($ x 1000)	$ 19,037.4	$ 19,037.4	$ -
Raft River Geothermal Expense ($ x 1000)	$ 4,589.5	$ 4,589.5	$ (0.0)
Total Expense Excl. CSPP ($ x 1000)	$ 60,797.3	$ 62,806.0	$ 2,008.6
Surplus Sales			
Energy (MWh)	2,666,462.4	2,465,858.4	(200,603.9)
Revenue Including Transmission Costs ($ x 1000)	$ 89,577.9	$ 83,151.7	$ (6,426.2)
Transmission Costs ($ x 1000)	$ 2,666.5	$ 2,465.9	$ (200.6)
Revenue Excluding Transmission Costs ($ x 1000)	$ 86,911.4	$ 80,685.8	$ (6,225.6)
Net Hedges			
Energy (MWh)	-	-	-
Cost($ X 1000)	$ -	$ -	$ -
			-
Net Power Supply Expenses ($ x 1000)	**$ 143,332.7**	**$143,663.1**	**$ 330.4**
			-
PURPA ($ x 1000)	$ 165,947.6	$ 165,947.6	$ -
			-
Total Net Power Supply Expenses ($ x 1000)	**$ 309,280.3**	**$309,610.8**	**$ 330.4**
			-
Sales at Customer Level (In 000s MWH)	14,186.526	14,186.526	-
			-
Hours in Month	8760	8760	-
			-
Unit Cost / MWH (for PCAM)	**$21.80**	**$21.82**	**$ 0.02**

Total Generation (Excluding PURPA)	16,051,061.8	15,850,457.9	(200,603.9)
Required Generation (Excluding PURPA)	13,384,599.5	13,384,599.4	(0.0)

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket UE 279 on the following named person(s) on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: May 6, 2014

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