BEFORE THE

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IDAHO PUBLIC
UTILITIES COMMISSION

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO.	)	CASE NO. IPC-E-08-10

DIRECT TESTIMONY OF RICK STERLING

IDAHO PUBLIC UTILITIES COMMISSION

OCTOBER 24, 2008

Q. Please state your name and business address for the record.

A. My name is Rick Sterling. My business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission as a Staff engineer.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Civil Engineering from the University of Idaho in 1981 and a Master of Science degree in Civil Engineering from the University of Idaho in 1983. I worked for the Idaho Department of Water Resources from 1983 to 1994. In 1988, I received my Idaho license as a registered professional Civil Engineer. I began working at the Idaho Public Utilities Commission in 1994. During my employment at the IPUC, I have attended the annual regulatory studies program sponsored by the National Association of Regulatory Commissioners (NARUC) at Michigan State University, as well as numerous other seminars and short courses.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss the

net power supply cost recommendation of Idaho Power, to explain why I believe it is too high, and to make an alternative recommendation that I believe fairly and reasonably represents the Company's normalized net power supply cost for the 2008 test year.

Q. Please briefly summarize your proposed net power supply cost adjustments.

A. I am proposing a net power supply cost of $77.6 million, which is approximately $11.2 million less than Idaho Power's proposed net power supply cost. My net power supply cost recommendation is based on the use of a natural gas price of $7.75 per MMBtu in the AURORA model.

Q. Have you reviewed the work done by Idaho Power to develop a net power supply cost recommendation for this case?

A. Yes, I have reviewed the Company's testimony and recommendations related to net power supply cost, and have also reviewed all of the supporting exhibits and workpapers prepared by the Company as well as all of the power supply cost simulations made using AURORA.

Q. What is Idaho Power recommending as the net power supply cost to be included in its revenue requirement?

A. Idaho Power is recommending a net power supply cost of $88.4 million in addition to PURPA costs of $63.3

million, for a total power supply cost of $151.7 million.

Q. Do you agree with the net power supply cost recommendations contained in the testimony of Idaho Power witness Greg Said?

A. No, I do not. I believe that the net power supply cost recommendations of the Company are too high. I do accept the Company's estimate of PURPA costs, however.

Q. Why do you believe that the net power supply cost recommendations of the Company are too high?

A. I believe that Idaho Power's net power supply cost recommendations are too high because of inaccurate assumptions made by the Company regarding natural gas fuel prices used in AURORA, the model used for computing net power supply costs.

Q. Are natural gas price assumptions crucial in the determination of net power supply costs, even though Idaho Power has a relatively small amount of natural gas fired generation on its system?

A. Yes, Idaho Power's net power supply costs are not only a function of the costs of fueling and operating its own generating resources, but are also a function of the costs of its off-system purchases and its secondary sales. During the majority of the year, gas-fired generation is the marginal resource in the region;

consequently, it tends to set the market price for all market purchases and sales. Obviously, higher gas prices drive electric market prices up and lower gas prices drive market prices down.

Q. How do high gas prices affect Idaho Power and its ratepayers?

A. High gas prices actually benefit Idaho Power and its ratepayers in most years. Because Idaho Power is a net energy seller over the course of the year, high gas prices, which in turn cause high electric market prices, allow the Company to sell its surplus low-cost hydro and coal generation at those higher market prices, substantially reducing its net power supply costs.

Q. What assumptions about gas price did Idaho Power make for purposes of its AURORA power supply cost simulations?

A. Idaho Power's derivation of the gas prices it used in AURORA is shown on Staff Exhibit No. 101. Idaho Power obtained 10-year gas price forecasts from three different sources—PIRA, DOE-EIA, and Global Insight—and five-year forecasts from two sources—NYMEX and NGX. Idaho Power computed a weighted average price using each of the ten years from 2008-2017, then made other adjustments to prepare the prices for input into the AURORA model. Idaho Power generated upper and lower

limits for gas prices to be used in AURORA by applying the standard deviation in actual prices at Sumas from 2001 through 2007. The result of this exercise was an average gas price of $7.74/MMBtu with upper and lower limits of $9.75/MMBtu and $5.73/MMBtu.

Q. How was this range of assumed gas prices used by Idaho Power in the AURORA model?

A. Idaho Power assumed that high gas prices are associated with low water conditions and that low gas prices occur when water conditions are high. For the 80 water years of record used in the power supply analysis, the Company created an algorithm that assigned the highest gas price ($9.75) to the lowest water year on record and assigned the lowest gas price ($5.73) to the highest water year on record. Gas prices were then assigned to all of the years in between based on their relative water condition.

Q. What is wrong with this approach in your opinion?

A. I believe that Idaho Power's approach is wrong for two reasons. First, I do not believe it is appropriate to use 10, or even five years of gas price forecasts when we are really only trying to establish power supply costs between now and when Idaho Power files its next general rate case. Idaho Power's last general

rate case was filed only about one year before this one, and the Company has indicated that it expects to make more frequent rate case filings in the future. Informally, Idaho Power has told Staff that its future rate case filings could be made as often as annually. Therefore, because we are likely only setting rates to be effective for approximately the next year, it seems logical that we should only be using gas price forecasts representative of the same time frame. Gas price forecasts five or ten years into the future have no relevance whatsoever when we are only setting rates one year into the future.

Q. What is your other primary objection to the method used by Idaho Power?

A. My second objection relates to Idaho Power's assumption that gas prices are directly related to hydro conditions. I do not believe that gas prices are correlated with hydro conditions on Idaho Power's system, or for that matter, even with Northwest hydro conditions. I believe that natural gas prices are influenced by numerous factors, most of which have nothing to do with water conditions in the Northwest. Because pipelines allow natural gas to be transported throughout North America, gas prices now tend to rise or fall in unison. Prices in the Northwest can be affected by a prolonged

cold snap in the Midwest, for example, by tropical storms and hurricanes in the Gulf, or by unusual demand in California. Underground gas storage levels, drilling activity, market speculation and economic conditions also significantly affect prices. Gas demand, wherever it occurs in the country, can affect prices nationally. Regional supply interruptions seem to be one of the few factors that can still significantly affect regional gas prices.

Q. Have you examined any data or performed any analysis to support your conclusion that gas prices and Northwest hydro conditions are not related?

A. Yes, I have. I performed regression analysis using historical Henry Hub and Sumas gas prices as reported by the Intercontinental Exchange and historical water conditions represented by hydro shaping factors used in AURORA. The hydro shaping factors used in AURORA reflect monthly and annual scaling factors used to accurately replicate historic hydro conditions in areas throughout the Northwest. The source for the hydro data used in AURORA is the Northwest Power Pool. Staff Exhibit No. 102 shows the results of the correlation analysis on a monthly basis for hydro conditions from 2001 through 2006 at Hells Canyon, Southern Idaho, run-of-river plants on Idaho Power's system, the Oregon-

Washington-Northern Idaho area, British Columbia and Montana. As shown by the exhibit, there appears to be no correlation whatsoever between Northwest hydro conditions and Sumas gas prices on a monthly basis. The results are similar for Henry Hub gas prices.

Q. Are you saying that neither gas prices nor hydro conditions affect power supply costs?

A. No, I am not suggesting that gas prices and hydro conditions do not affect power supply costs. Clearly, both greatly affect power supply costs. They do so independently, however. What I am saying is that gas prices are unrelated to Northwest hydro conditions.

Q. What gas prices did you consider using for the power supply analysis in AURORA?

A. I believe it is reasonable to use gas prices representative of 2009, the year when the rates determined in this case will be effective. To obtain prices representative of 2009, I considered several forecasts available to Staff. First, I considered the August 2008 forecast prepared by Global Insight because it was more recent than the March 2008 Global Insight forecast used by Idaho Power in developing the Company's gas price forecast. I also considered the Department of Energy/Energy Information Administration's (EIA) Annual Energy Outlook forecast that was released in June 2008.

In addition, I considered EIA's Short Term Energy Outlook forecasts released monthly in 2008 from January through October. In addition to these forecasts, I considered the most recent 12 months of NYMEX spot market prices and NYMEX forwards prices for 2009. I also reviewed recent forecasts made by gas industry experts as reported quarterly in the publication *Natural Gas Week*.

Q. Do you consider these sources to be superior to those used by Idaho Power?

A. All of the forecasts I considered were more recent than the forecast information used by Idaho Power. I had an advantage in my analysis because all of the gas price information I considered was simply not yet available at the time the Company prepared its case.

Q. Were gas price forecasts for 2009 reasonably consistent throughout the past year?

A. No, gas price forecasts for 2009 and 2009 gas forwards prices were extremely variable during the past year. Exhibit No. 103 shows how dramatically 2009 gas forwards prices varied throughout 2008.

Q. Why did 2009 gas forwards prices vary so much during the year?

A. There were several extremely unusual events in 2008 that had major impacts on 2009 forwards prices. First, oil prices began climbing in the first half of the

year, eventually reaching record levels. Natural gas prices followed a similar trend until July 1, when winter 2009 forwards prices peaked at over $14 per MMBtu. In less than a month and a half, prices plummeted to the $8 per MMBtu range. Two major hurricanes in the Gulf during September also affected prices. Finally, the recent economic crisis and Wall Street bailout plan have lowered forecast prices even further due to expectations of a global economic downturn. These highly unusual events have made it extremely difficult to forecast prices even one year into the future. Selecting gas prices in recent months for use in power supply modeling has truly been a case of chasing a moving target.

Q. What gas prices do you believe should be used for power supply modeling in AURORA?

A. My recommendation is to use a gas price of $7.75 per MMBtu for all 80 water years based on the natural gas price forecast contained in the Energy Information Administration's October 2008 Short Term Energy Outlook. That is the forecasted price for 2009 (in year 2008 dollars).

Q. Why did you decide to rely on just one recent forecast rather than using a blend of forecasts like Idaho Power or using an average of several forecasts prepared at different times during the year?

A. Because of the extreme events during the past year, gas forecasts prepared early in the year could not take into account the effect of recent events. The extreme rise and fall in oil and natural gas prices and the economic credit crisis, in particular, are two events whose effects can only be reflected in very recent price forecasts. I chose to use the freshest forecast available at the time I prepared my testimony. Because multiple recent forecasts were not available, blending forecasts was not an option. Furthermore, blending forecasts prepared at different points in time when economic conditions are extremely different would be inadvisable.

Q. Why do you propose to use the same gas price for all 80 water years?

A. I believe it is appropriate to use the same gas price for all 80 water years because I have found no evidence to suggest that gas prices vary based on water conditions. The purpose of using 80 different water years is to simulate normal water conditions during the test year. Normal gas prices for the test year can be simulated with only a single estimate because gas prices are unrelated to water conditions.

Q. What net power supply cost do you calculate using AURORA with the $7.75 per MMBtu gas price you

1 believe should be used?

2 A. Using a gas price of $7.75 per MMBtu for all
3 water years, AURORA calculated a net power supply cost of
4 $77.6 million. Net power supply costs are comprised of
5 four accounts: 447 System Opportunity Sales; 501 Fuel
6 (Coal); 547 Fuel (Gas); and 555.1 Purchased Power.
7 Staff's proposed totals for each account are shown on
8 Exhibit No. 104, and are also compared to Idaho Power's
9 proposed amounts. Staff's most significant adjustment is
10 a $6.4 million increase in account 447 System Opportunity
11 Sales.

12 Q. The $7.75 per MMBtu gas price that you used for
13 AURORA modeling is only one cent higher than the price
14 Idaho Power used for its modeling. Why did such a small
15 difference in gas price cause your power supply costs to
16 be $11.2 million lower than Idaho Power's?

17 A. The extremely small difference in annual gas
18 price assumptions is not a significant reason for the
19 substantial difference in net power supply costs. The
20 primary reason why my results differ so much from Idaho
21 Power's is because I did not assume a correlation between
22 water conditions and gas prices, as I explained
23 previously. Idaho Power assumes that the highest gas
24 prices (thus the highest electric prices) will occur in
25 the lowest water years. In those low-water/high-price

years, Idaho Power will have little or no surplus power to sell, and instead will likely need to buy power at those high prices. Idaho Power assumes the opposite situation in high water years, i.e., that in years when it has a lot of surplus power to sell, gas and electric prices will be low. Compared to my assumptions, the Company's assumptions produce lower revenues in high-water years and higher costs in low-water years.

Q. Did you make any other changes to the AURORA input assumptions that are different from those used by Idaho Power?

A. Yes, I made two changes that had a comparatively minor effect. First, I decreased the gas price basis differential between Henry Hub and Danskin. Idaho Power used a basis differential of $0.27 per MMBtu. I performed analysis of Henry Hub to Sumas basis differentials using NYMEX forwards prices, then accounted for delivery costs from Sumas to Danskin, and determined that a basis differential of $0.13 is more appropriate.

Second, I modified the "monthly shape factors" for the gas prices used in AURORA. Monthly shape factors are basically multipliers that are used to convert an annual gas price (in this case $7.75 per MMBtu) to a series of twelve different monthly prices. My modification was based on analysis of 2009 monthly gas

forwards prices as quoted daily by NYMEX for the past twelve months.

Except for these two changes, I used all of Idaho Power's other assumptions in AURORA. A summary of the results of this AURORA simulation is presented in Staff Exhibit No. 105.

Q. Have you prepared an exhibit comparing your net power supply cost recommendations to Idaho Power's?

A. Yes, Staff Exhibit No. 106 compares my recommendation for net power supply cost to Idaho Power's. The exhibit also shows the PURPA costs that are added to get total power supply cost, as well as the normalized power supply costs adopted in the Company's last general rate case. Note that even under Staff's recommendation, net power supply costs are more than double what they were in the Company's last general rate case.

Q. Did you make any AURORA runs using gas prices from Idaho Power's own gas forecast?

A. No, I did not. I did not use Idaho Power's own forecasted gas prices for 2009 because all of the forecasts used by Idaho Power were made in March – before the extreme run-up in prices prior to July, before the precipitous drop in prices in July and August, before hurricanes Gustav and Ike, and before the credit crisis

in October. I do not believe any forecasts for 2009 that were made in March 2008 should be relied upon for power supply modeling. Idaho Power's forecasted price for 2009 was $8.89 per MMBtu. I believe that price is clearly too high. Such high gas prices produce net power supply cost results that are unrealistically low. Using my other assumptions, a price of $8.89 per MMBtu would have produced a net power supply cost of approximately $64.5 million.

Q. Have you prepared an exhibit to compare Idaho Power's net power supply recommendation, your recommendation, and other net power supply results obtained using other possible gas price assumptions?

A. Yes, I have. Staff Exhibit No. 107 shows the effect of various gas price assumptions on net power supply costs and compares my recommended result to the Company's. As the results show, my recommended net power supply cost is below the Company's recommendation, but higher than it would be if several other gas forecasts were used. Compared to the results obtained using other possible gas prices, I believe my recommendation is conservative.

Q. What happens if Idaho Power's actual net power supply costs turn out to be different than those adopted in this general rate case?

A. If actual power supply costs in the future are different than those adopted in this general rate case, then the difference will be considered in the annual Power Cost Adjustment (PCA) until the Company's next general rate case. Under the PCA, 90 percent of the difference between the annual projected power cost and the Commission approved base power cost as established in this case will be credited to or collected from customers. Consequently, Idaho Power will never be at risk for more than 10 percent of the difference between projected power supply costs and the base power supply costs.

Q. Can you validate the AURORA model by comparing predicted results to actual net power supply costs from prior years, say for 2007?

A. Although it is possible to compare simulated results to actual historical results, the two will probably never be equal even if historical gas prices and hydro conditions are replicated. Actual electric market prices are affected by many things besides just hydro conditions and natural gas prices. Many factors that affect actual power supply costs simply cannot easily be replicated on an actual basis in AURORA, such as weather, plant outages, fuel supply interruptions, and market speculation. The 2007 water year results from the "base

case" used to determine power supply costs in this case will not match actual 2007 power supply costs because the "base case" for 2007 only differs from the other 79 years used in the analysis by the hydro conditions. The base case for 2007 does not use actual gas prices in 2007, actual demand in 2007, or any other actual data from 2007. The 2007 results only reflect 2007 water conditions and nothing more.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

IDAHO POWER COMPANY
GAS PRICE FORECAST
2008 $/MMBTU

Year	PIRA Sumas	PIRA Wgt	NYMEX Sumas	NYMEX Wgt	NGX Sumas	NGX Wgt	EIA Sumas	EIA Wgt	Global Insight Sumas	Global Insight Wgt	Total Wgts
2008	$ 9.22	14%	$ 8.86	29%	$ 8.81	29%	$ 6.87	14%	$ 7.20	14%	100%
2009	$ 7.30	14%	$ 7.91	29%	$ 7.92	29%	$ 7.30	14%	$ 7.56	14%	100%
2010	$ 5.87	14%	$ 7.40	29%	$ 7.40	29%	$ 6.51	14%	$ 7.21	14%	100%
2011	$ 5.61	14%	$ 7.54	29%	$ 7.54	29%	$ 6.07	14%	$ 7.09	14%	100%
2012	$ 5.90	14%	$ 7.88	29%	$ 7.11	29%	$ 5.92	14%	$ 6.95	14%	100%
2013	$ 6.42	14%	$ 8.51	29%	$ 7.65	29%	$ 5.67	14%	$ 6.74	14%	100%
2014	$ 6.85	54%					$ 5.48	23%	$ 6.77	23%	100%
2015	$ 7.25	54%					$ 5.34	23%	$ 6.78	23%	100%
2016	$ 7.62	54%					$ 5.28	23%	$ 6.86	23%	100%
2017	$ 8.05	54%					$ 5.34	23%	$ 6.87	23%	100%
AVERAGE 2008 to 2017	$ 7.01		$ 8.01		$ 7.74		$ 5.98		$ 7.00		
	$ (0.57)		$ (0.57)		$ (0.57)		$(0.57)		$ (0.57)		
	$ 7.58	HH	$ 8.58	HH	$ 8.31	HH	$ 6.54	HH	$ 7.57	HH	

Year	Sumas $/MMBtu	Transport $/MMBtu Fixed	Transport $/MMBtu Aca/demand	Transport $/MMBtu Fuel Gas-1.99%	Danskin Delivered $/MMBtu	HH to Sumas Basis Adj $/MMBTu (2008 $)	2008 Dollars Henry Hub $/MMBtu
2008	$ 8.38	$ 0.3788	$ 0.0319	$ 0.17	$ 8.96	$ (0.510)	$ 8.89
2009	$ 7.69	$ 0.3798	$ 0.0319	$ 0.15	$ 8.26	$ (0.200)	$ 7.89
2010	$ 7.03	$ 0.3798	$ 0.0319	$ 0.14	$ 7.58	$ (0.526)	$ 7.56
2011	$ 7.00	$ 0.3798	$ 0.0319	$ 0.14	$ 7.55	$ (0.626)	$ 7.63
2012	$ 6.97	$ 0.3788	$ 0.0319	$ 0.14	$ 7.52	$ (0.581)	$ 7.55
2013	$ 7.32	$ 0.3798	$ 0.0319	$ 0.15	$ 7.88	$ (0.616)	$ 7.94
2014	$ 6.52	$ 0.3798	$ 0.0319	$ 0.13	$ 7.06	$ (0.633)	$ 7.15
2015	$ 6.70	$ 0.3798	$ 0.0319	$ 0.13	$ 7.25	$ (0.649)	$ 7.35
2016	$ 6.91	$ 0.3788	$ 0.0319	$ 0.14	$ 7.45	$ (0.659)	$ 7.56
2017	$ 7.15	$ 0.3798	$ 0.0319	$ 0.14	$ 7.71	$ (0.672)	$ 7.83
AVERAGE 2008 to 2017	$ 7.17	$ 0.38	$ 0.03	$ 0.14	$ 7.72	$ (0.567)	$ 7.74
				Basis :	$ 0.554		
				(Sumas to Danskin)			

					$ 7.74
Standard Deviation in actual prices at Sumas from January 1, 2001 to December 31, 2007:					$ 1.99
					25.72%
High:	$ 7.74	x	1.26	=	$ 9.75
Low:	$ 7.74	x	0.74	=	$ 5.73

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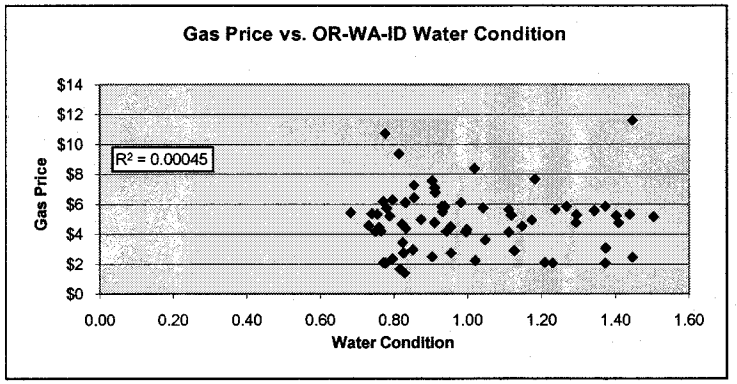
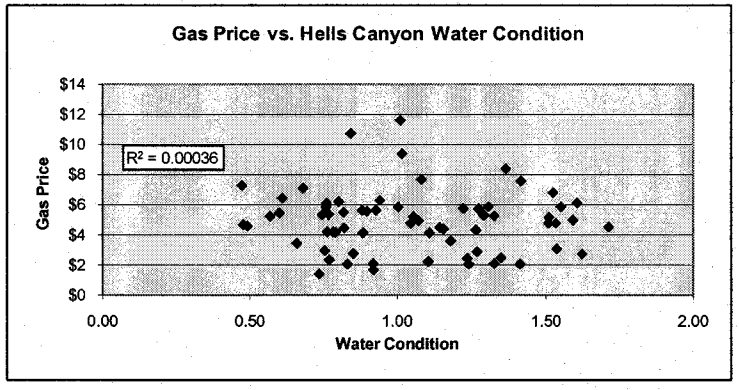
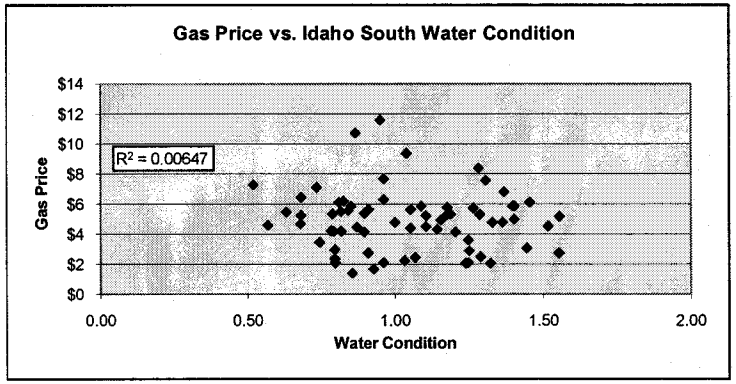
NOTES:
1) NWP Transport includes rate case adjustment of 3.5 cents in 2006 and 7.0 cents thereafter
2) Basis Adjustment from IGI Resources forecast (2007-2009)

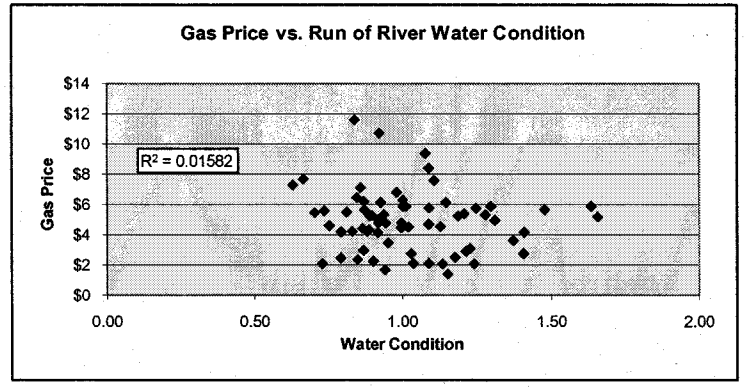
Correlations Between Monthly Northwest Water Conditions and Gas Prices at Sumas

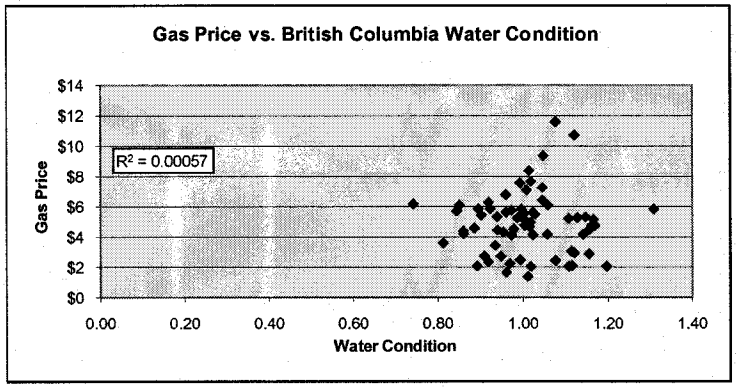
May 2001- December 2006

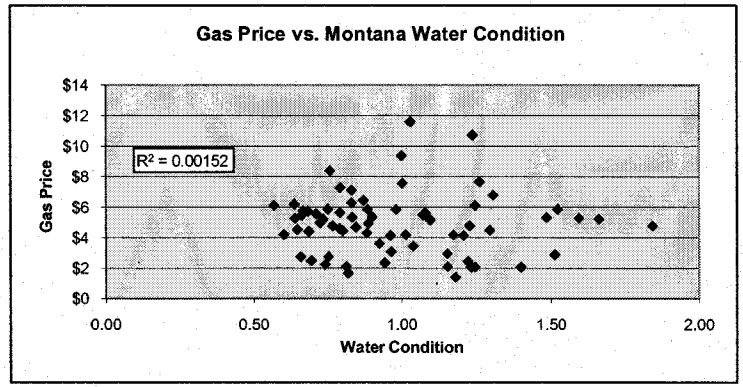












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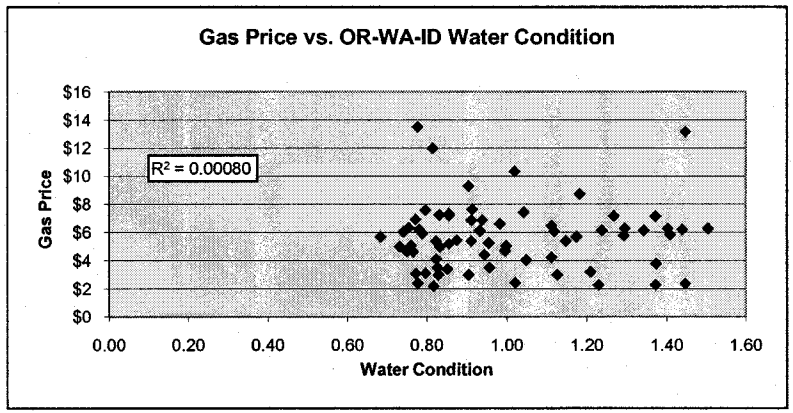
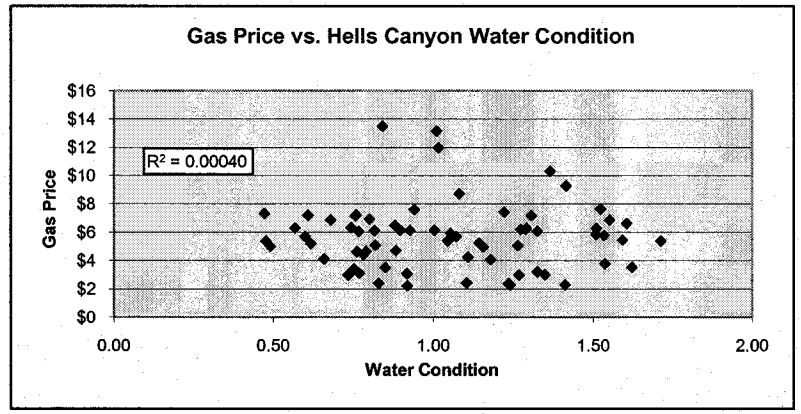
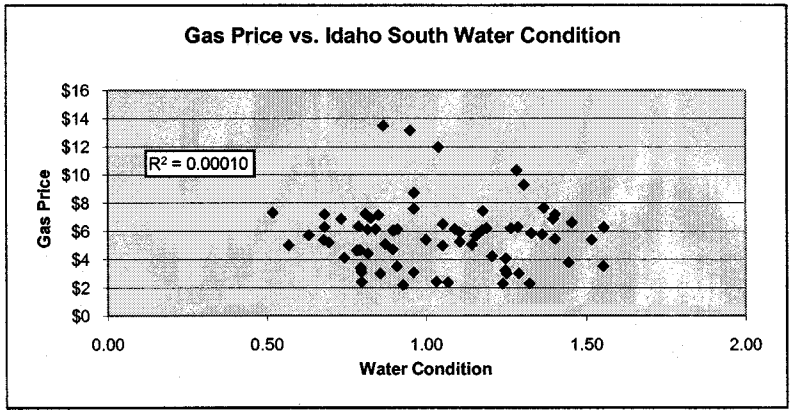
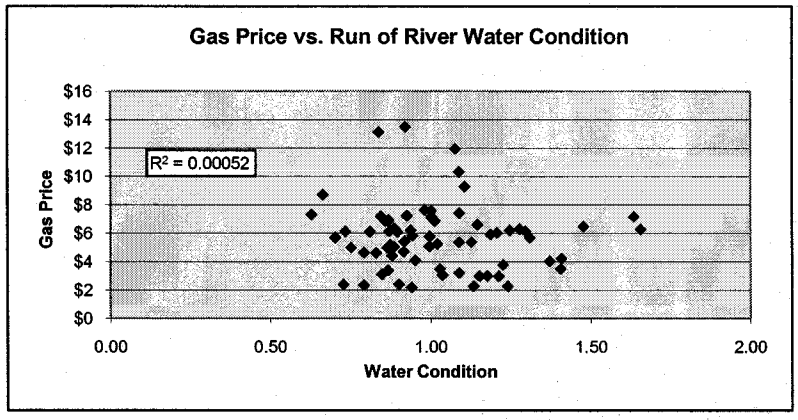
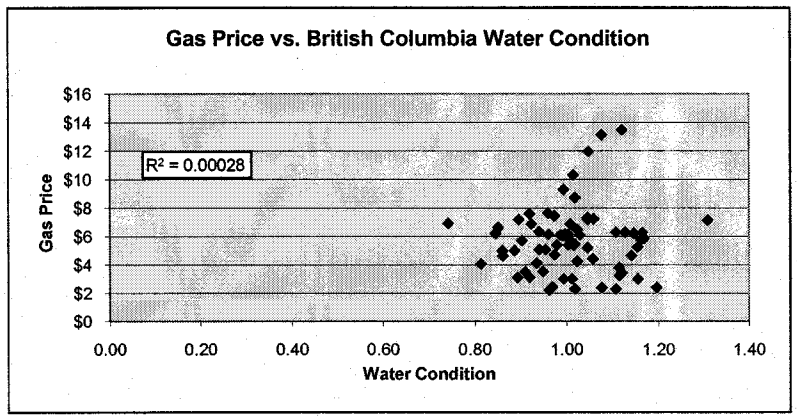
Correlations Between Monthly Northwest Water Conditions and Gas Prices at Henry Hub
April 2001- December 2006

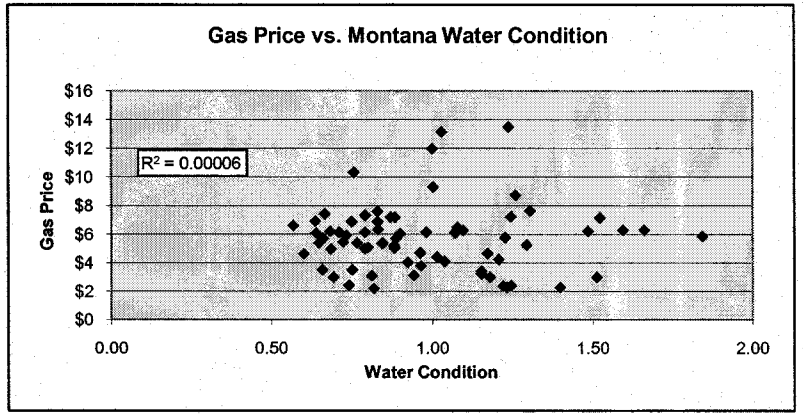












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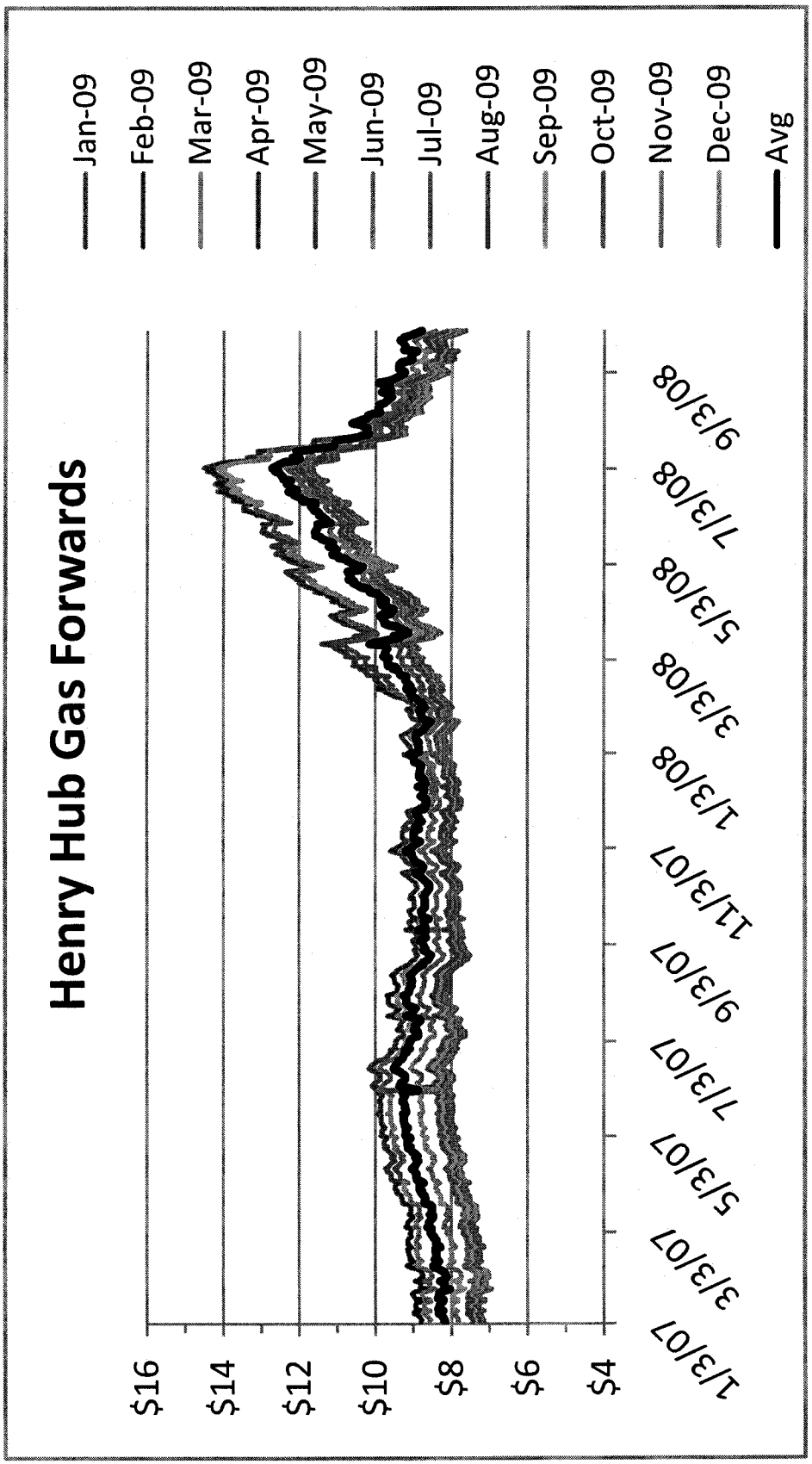

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Net Power Supply Cost Adjustments by Account

Account	Description	IPCo Proposal	Staff Proposal	Adjustment
447	**System Opportunity Sales**			
	System Opportunity Sales	$ 110,210,425	$ 116,568,567	$ 6,358,142
501	**Fuel (Coal)**			
	Bridger	$ 82,101,940	$ 82,077,624	$ (24,316)
	Boardman	$ 6,035,719	$ 6,022,749	$ (12,971)
	Valmy	$ 45,280,425	$ 45,354,350	$ 73,925
	Subtotal	$ 133,418,084	$ 133,454,723	$ 36,639
547	**Fuel (Gas)**			
	Danskin	$ 6,307,632	$ 5,554,274	$ (753,357)
	Bennett Mountain	$ 779,236	$ 570,905	$ (208,331)
	Subtotal	$ 7,086,868	$ 6,125,180	$ (961,688)
555	**Purchased Power**			
	Purchased Power	$ 58,126,719	$ 54,565,145	$ (3,561,574)
Total Net Power Supply Cost		**$ 88,421,246**	**$ 77,576,480**	**$ (10,844,766)**
555	Transmission Losses	$ 3,051,318	$ 2,666,773	$ (384,545)
Total Net Power Supply Cost including Trans Losses		**$ 91,472,564**	**$ 80,243,253**	**$ (11,229,311)**

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2008 NORMALIZED NET POWER SUPPLY COSTS

Scenario 1

Thermal Generation (MWh) (Br, Bo, V)		7,444,117	
Hydro Generation (MWh)		6,193,320	
Combustion Turbine (MWh)		68,315	
Total Market Purchases (MWh)		1,091,102	
Total Market Sales (MWh)		564,310	
Total Thermal Unit Fuel Costs ($000)*	1/	139,319	
Total Market Purchases ($000)		67,479	$61.84
Total Market Sales ($000)		32,217	$57.09
Net Power Supply Costs ($000)		174,581	

* Bridger, Boardman, Valmy, Danskin, Bennett Mt

2008 Normalized Thermal Output (MWh)		aMW
Jim Bridger	5,098,743	580
Valmy	1,913,229	218
Boardman	432,145	49
Danskin	53,509	6
Bennett Mt	14,806	2
2008 Normalized Cost ($000)		**$/MWh**
Jim Bridger	82,211	$16.12
Valmy	46,090	$24.09
Boardman	6,192	$14.33
Danskin	3,754	$70.16
Bennett Mt	1,072	$72.42

Scenario 2

Thermal Generation (MWh) (Br, Bo, V)		7,429,752	
Hydro Generation (MWh)		7,429,648	
Combustion Turbine (MWh)		41,854	
Total Market Purchases (MWh)		664,477	
Total Market Sales (MWh)		1,333,097	
Total Thermal Unit Fuel Costs ($000)*		137,187	
Total Market Purchases ($000)		40,248	$60.57
Total Market Sales ($000)		73,947	$55.47
Net Power Supply Costs ($000)		103,487	

* Bridger, Boardman, Valmy, Danskin, Bennett Mt

2008 Normalized Thermal Output (MWh)		aMW
Jim Bridger	5,097,825	580
Valmy	1,903,266	217
Boardman	428,661	49
Danskin	31,519	4
Bennett Mt	10,335	1
2008 Normalized Cost ($000)		**$/MWh**
Jim Bridger	82,196	$16.12
Valmy	45,866	$24.10
Boardman	6,146	$14.34
Danskin 1/	2,230	$70.74
Bennett Mt	749	$72.45

Scenario 3

Thermal Generation (MWh) (Br, Bo, V)		7,406,067	
Hydro Generation (MWh)		8,637,374	
Combustion Turbine (MWh)		27,197	
Total Market Purchases (MWh)		367,440	
Total Market Sales (MWh)		2,205,336	
Total Thermal Unit Fuel Costs ($000)*		135,680	
Total Market Purchases ($000)		21,426	$58.31
Total Market Sales ($000)		114,375	$51.86
Net Power Supply Costs ($000)		42,730	

* Bridger, Boardman, Valmy, Danskin, Bennett Mt

2008 Normalized Thermal Output (MWh)		aMW
Jim Bridger	5,093,213	580
Valmy	1,888,365	215
Boardman	424,490	48
Danskin	20,570	2
Bennett Mt	6,627	1
2008 Normalized Cost ($000)		**$/MWh**
Jim Bridger	82,121	$16.12
Valmy	45,531	$24.11
Boardman	6,091	$14.35
Danskin 1/	1,456	$70.77
Bennett Mt	480	$72.49

Scenario 4

Thermal Generation (MWh) (Br, Bo, V)		7,381,227	
Hydro Generation (MWh)		9,900,506	
Combustion Turbine (MWh)		22,468	
Total Market Purchases (MWh)		220,978	
Total Market Sales (MWh)		3,292,332	
Total Thermal Unit Fuel Costs ($000)*		134,853	
Total Market Purchases ($000)		12,403	$56.13
Total Market Sales ($000)		162,701	$49.42
Net Power Supply Costs ($000)		(15,444)	

* Bridger, Boardman, Valmy, Danskin, Bennett Mt

2008 Normalized Thermal Output (MWh)		aMW
Jim Bridger	5,091,732	580
Valmy	1,871,165	213
Boardman	418,330	48
Danskin	16,884	2
Bennett Mt	5,584	1
2008 Normalized Cost ($000)		**$/MWh**
Jim Bridger	82,098	$16.12
Valmy	45,144	$24.13
Boardman	6,014	$14.38
Danskin 1/	1,193	$70.67
Bennett Mt	405	$72.51

Scenario 5

Thermal Generation (MWh) (Br, Bo, V)		7,289,636	
Hydro Generation (MWh)		11,581,966	
Combustion Turbine (MWh)		8,878	
Total Market Purchases (MWh)		57,079	
Total Market Sales (MWh)		4,704,463	
Total Thermal Unit Fuel Costs ($000)*		132,210	
Total Market Purchases ($000)		2,858	$50.07
Total Market Sales ($000)		211,702	$45.00
Net Power Supply Costs ($000)		(76,635)	

* Bridger, Boardman, Valmy, Danskin, Bennett Mt

2008 Normalized Thermal Output (MWh)		aMW
Jim Bridger	5,070,926	577
Valmy	1,826,621	208
Boardman	392,089	45
Danskin	6,837	1
Bennett Mt	2,041	0
2008 Normalized Cost ($000)		**$/MWh**
Jim Bridger	81,762	$16.12
Valmy	44,141	$24.17
Boardman	5,671	$14.46
Danskin 1/	487	$71.27
Bennett Mt	148	$72.63

AVERAGE OF ALL YEARS

Thermal Generation (MWh) (Br, Bo, V)		7,390,160	
Hydro Generation (MWh)		8,748,563	998.7
Combustion Turbine (MWh)		33,742	
Total Market Purchases (MWh)		480,215	
Total Market Sales (MWh)		2,419,908	
Total Thermal Unit Fuel Costs ($000)*		135,850	
Total Market Purchases ($000)		28,883	$60.15
Total Market Sales ($000)		118,988	$49.17
Net Power Supply Costs ($000)		45,744	
* Bridger,Boardman,Valmy, Bennett and	Danskin-Fixed	3,730	
Danskin (excl fixed)	Contracts	25,682	
1/ Excludes Danskin Fixed	Wheeling	2,420	
	Avg NPSC	**77,576**	

2007 Normalized Thermal Output (MWh)		aMW
Jim Bridger	5,090,488	580
Valmy	1,880,529	214
Boardman	419,143	48
Danskin	25,864	3
Bennett Mt	7,879	1
2007 Normalized Cost ($000)		**$/MWh**
Jim Bridger	82,078	$16.12
Valmy	45,354	$24.12
Boardman	6,023	$14.37
Danskin 1/	1,824	$70.52
Bennett Mt	571	$72.46

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IPCO POWER SUPPLY COSTS FOR 2008 NORMALIZED LOADS OVER 80 WATER YEAR CONDITIONS

AVERAGE

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	743,548.7	888,803.6	870,114.3	864,268.9	866,449.0	842,395.2	727,873.1	688,036.5	555,471.4	527,759.4	478,321.1	695,521.7	8,748,562.8
Bridger													
Energy (MWh)	455,179.3	425,812.9	421,981.5	330,372.1	330,320.5	425,111.7	455,179.3	455,179.3	440,496.2	455,179.3	440,496.2	455,179.3	5,090,487.7
Cost ($ x 1000)	$ 7,339.2	$ 6,865.7	$ 6,803.9	$ 5,326.8	$ 5,326.0	$ 6,854.5	$ 7,339.2	$ 7,339.2	$ 7,102.4	$ 7,339.2	$ 7,102.4	$ 7,339.2	$ 82,077.6
Boardman													
Energy (MWh)	38,064.9	35,490.4	38,688.9	30,780.7	6,437.4	27,848.5	40,271.2	41,017.5	39,484.0	40,923.9	39,398.5	40,737.2	419,143.0
Cost ($ x 1000)	$ 548.5	$ 512.0	$ 556.5	$ 443.5	$ 94.4	$ 412.4	$ 576.3	$ 585.6	$ 564.1	$ 584.4	$ 563.0	$ 582.1	$ 6,022.7
Valmy													
Energy (MWh)	163,466.2	151,863.0	161,017.3	82,453.3	150,204.7	146,519.6	171,941.9	172,718.1	165,920.4	172,302.4	167,940.0	174,182.2	1,880,529.1
Cost ($ x 1000)	$ 3,946.3	$ 3,667.9	$ 3,891.2	$ 2,000.2	$ 3,635.2	$ 3,556.8	$ 4,137.2	$ 4,154.7	$ 3,993.1	$ 4,145.4	$ 4,038.6	$ 4,187.7	$ 45,354.4
Danskin													
Energy (MWh)	362.2	103.1	9.5	1,565.3	21.3	156.9	13,478.9	5,904.3	931.2	678.3	2,011.4	641.3	25,863.7
Cost ($ x 1000)	$ 31.9	$ 9.1	$ 0.8	$ 105.6	$ 1.4	$ 10.5	$ 930.1	$ 410.9	$ 64.8	$ 48.3	$ 157.2	$ 53.4	$ 1,824.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.5	$ 296.9	$ 315.5	$ 306.2	$ 315.5	$ 306.2	$ 315.5	$ 315.5	$ 306.2	$ 315.5	$ 306.2	$ 315.5	$ 3,730.3
Total Cost	$ 347.4	$ 306.0	$ 316.3	$ 411.8	$ 316.9	$ 316.7	$ 1,245.6	$ 726.4	$ 371.0	$ 363.8	$ 463.5	$ 368.9	$ 5,554.3
Bennett Mountain													
Energy (MWh)	7.0	1.0	-	4.9	-	3.1	5,383.3	2,352.2	50.2	14.1	44.1	18.8	7,878.6
Cost ($ x 1000)	$ 0.6	$ 0.1	$ -	$ 0.3	$ -	$ 0.2	$ 388.6	$ 171.0	$ 3.7	$ 1.1	$ 3.6	$ 1.6	$ 570.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ 0.6	$ 0.1	$ -	$ 0.3	$ -	$ 0.2	$ 388.6	$ 171.0	$ 3.7	$ 1.1	$ 3.6	$ 1.6	$ 570.9
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	37,924.2	607.9	600.4	3,189.6	12,896.3	46,695.4	152,850.1	67,595.6	48,630.0	3,924.0	38,986.4	66,315.4	480,215.3
Contract Energy (MWh)	34,868.2	32,401.5	35,271.0	34,356.0	31,709.3	68,147.5	72,599.6	67,511.3	30,031.7	35,463.5	32,718.0	42,172.0	517,249.5
Total Energy Excl. CSPP (MWh)	72,792.4	33,009.3	35,871.4	37,545.6	44,605.6	114,842.9	225,449.7	135,106.8	78,661.7	39,387.5	71,704.5	108,487.4	997,464.7
Market Cost ($ x 1000)	$ 2,337.4	$ 37.5	$ 30.5	$ 158.0	$ 675.5	$ 2,083.3	$ 9,230.6	$ 3,919.1	$ 3,070.5	$ 262.3	$ 2,757.2	$ 4,320.8	$ 28,882.7
Contract Cost ($ x 1000)	$ 1,764.2	$ 1,639.7	$ 1,311.4	$ 1,277.2	$ 1,182.0	$ 3,250.2	$ 3,841.6	$ 3,560.3	$ 1,523.8	$ 1,793.7	$ 1,988.0	$ 2,550.5	$ 25,682.5
Total Cost Excl. CSPP ($ x 1000)	$ 4,101.6	$ 1,677.1	$ 1,341.9	$ 1,435.2	$ 1,857.5	$ 5,333.5	$ 13,072.2	$ 7,479.4	$ 4,594.3	$ 2,056.0	$ 4,745.2	$ 6,871.2	$ 54,565.1
Surplus Sales													
Energy (MWh)	188,669.4	421,357.2	421,058.3	363,690.9	262,784.9	241,822.9	27,751.6	26,129.3	103,716.2	180,869.9	81,547.2	100,509.9	2,419,907.8
Revenue Including Transmission Costs ($ x 1000)	$ 10,012.6	$ 23,030.3	$ 21,829.0	$ 17,186.0	$ 10,974.9	$ 7,803.6	$ 1,527.5	$ 1,533.8	$ 5,393.9	$ 9,317.2	$ 4,140.2	$ 6,239.3	$ 118,988.5
Transmission Costs ($ x 1000)	$ 188.7	$ 421.4	$ 421.1	$ 363.7	$ 262.8	$ 241.8	$ 27.8	$ 26.1	$ 103.7	$ 180.9	$ 81.5	$ 100.5	$ 2,419.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 9,824.0	$ 22,608.9	$ 21,408.0	$ 16,822.4	$ 10,712.1	$ 7,561.8	$ 1,499.7	$ 1,507.7	$ 5,290.2	$ 9,136.3	$ 4,058.6	$ 6,138.8	$ 116,568.6
Net Power Supply Costs ($ x 1000)	$ 6,459.7	$ (9,580.1)	$ (8,498.2)	$ (7,204.5)	$ 517.8	$ 8,912.4	$ 25,259.4	$ 18,948.6	$ 11,338.4	$ 5,353.5	$ 12,857.7	$ 13,211.9	$ 77,576.5

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Summary Comparison of Net Power Supply Costs

	Net Power Supply Cost	PURPA	Total
Idaho Power Case	$ 88.4	$ 63.3	$ 151.7
Staff Case	$ 77.6	$ 63.3	$ 140.9
Difference	$ 10.8	$ -	$ 10.8
2007 Normalized Adopted Costs	$ 34.9	$ 93.1	$ 128.0

All costs shown are in million $

Including costs due to transmission losses, the difference between Staff's case and Idaho Power's case is $11.2 million.

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Summary of AURORA Results

AVERAGE OF ALL YEARS		IPCo Case IPCo Shapes $9.75 to $5.73; $7.74 avg; correlated to hydro	IPCo Gas Staff Shapes	EIA STEO Aug-08 Staff Shapes $8.55 Gas	EIA STEO Sep-08 IPCo Shapes $8.10 Gas	EIA STEO Sep-08 Staff Shapes $8.10 Gas	EIA STEO Oct-08 Staff Shapes $7.75 Gas
Thermal Generation (MWh) (Br, Bo, V)		7,389,498	7,389,332	7,394,500	7,391,828	7,391,907	7,390,160
Hydro Generation (MWh)		8,748,563	8,748,563	8,748,563	8,748,563	8,748,563	8,748,563
Combustion Turbine (MWh)		41,765	44,420	36,068	33,686	34,698	33,742
Total Market Purchases (MWh)		471,980	472,249	477,406	478,474	478,935	480,215
Total Market Sales (MWh)		2,419,052	2,421,851	2,423,769	2,419,740	2,421,333	2,419,908
Total Thermal Unit Fuel Costs ($000)*		136,775	136,925	136,378	136,040	136,070	135,850
Total Market Purchases ($000)		32,444	32,333	31,782	30,244	30,149	28,883
Total Market Sales ($000)		112,629	113,897	131,584	123,285	124,491	118,988
Net Power Supply Costs ($000)		56,589	55,361	36,575	42,999	41,727	45,744
* Bridger,Boardman,Valmy,Danskin(excl fixed)	Danskin-Fixed	3,730	3,730	3,730	3,730	3,730	3,730
and Bennett Mountain	PPL	25,682	25,682	25,682	25,682	25,682	25,682
1/ Excludes Danskin Fixed	Wheeling	2,419	2,422	2,424	2,420	2,421	2,420
	Avg NPSC	**88,421**	**87,195**	**68,411**	**74,831**	**73,561**	**77,676**
Avg Market Purchase Price ($/MWh)		$68.74	$68.47	$66.57	$63.21	$62.95	$60.15
Avg Market Sales Price ($/MWh)		$46.56	$47.03	$54.29	$50.95	$51.41	$49.17

Summary of AURORA Results

AVERAGE OF ALL YEARS		EIA STEO Oct-08 IPCo Shapes $7.75 Gas	IPCo Avg Gas Staff Shapes $7.74 Gas $0.27 Basis	NYMEX 30_day Avg Staff Shapes $8.72 Gas	NYMEX 12-mo Avg Staff Shapes $8.82 Gas
Thermal Generation (MWh) (Br, Bo, V)		7,389,413	7,390,113	7,395,829	7,396,442
Hydro Generation (MWh)		8,748,563	8,748,563	8,748,563	8,748,563
Combustion Turbine (MWh)		32,757	42,811	36,584	36,596
Total Market Purchases (MWh)		479,826	474,623	476,668	476,528
Total Market Sales (MWh)		2,417,746	2,423,392	2,424,877	2,425,364
Total Thermal Unit Fuel Costs ($000)*		135,809	136,448	136,503	136,551
Total Market Purchases ($000)		28,973	28,396	32,394	32,766
Total Market Sales ($000)		117,842	119,102	134,229	135,809
Net Power Supply Costs ($000)		46,940	45,742	34,668	33,508
* Bridger,Boardman,Valmy,Danskin(excl fixed)	Danskin-Fixed	3,730	3,730	3,730	3,730
and Bennett Mountain	PPL	25,682	25,682	25,682	25,682
1/ Excludes Danskin Fixed	Wheeling	2,418	2,423	2,425	2,425
	Avg NPSC	**78,770**	**77,578**	**66,505**	**65,346**
Avg Market Purchase Price ($/MWh)		$60.38	$59.83	$67.96	$68.76
Avg Market Sales Price ($/MWh)		$48.74	$49.15	$55.36	$56.00

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 24TH DAY OF OCTOBER 2008, SERVED THE FOREGOING **DIRECT TESTIMONY OF RICK STERLING,** IN CASE NO. IPC-E-08-10, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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SECRETARY

CERTIFICATE OF SERVICE