BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

RECEIVED
2009 MAY 29 AM 11:
IDAHO PUBLIC
UTILITIES COMMISSI

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO.	)	CASE NO. AVU-E-09-1/ AVU-G-09-1

DIRECT TESTIMONY OF RICK STERLING

IDAHO PUBLIC UTILITIES COMMISSION

MAY 29, 2009

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 Energy Division from 1983 to 1994. In 1988, I became licensed in Idaho as a registered professional Civil Engineer. I began working at the Idaho Public Utilities Commission in 1994. My duties at the Commission include analysis of a wide variety of electric and large water utility applications.

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

A. The purpose of my testimony is to review the power supply modeling computations of Avista witness Kalich and the power supply pro forma adjustment calculations of Company witness Johnson. I propose changes to the gas price assumptions used for power supply modeling, and I propose removing all term (less than 18 months) gas and electric transactions from the analysis used to compute power supply costs for inclusion in base rates.

Q. What model did the Company use to dispatch its portfolio of resources and obligations?

A. Avista uses the AURORA model for determining power supply costs. Staff has a license to use the AURORA model (courtesy of Avista), and possesses the ability to run the model and interpret its results. The model optimizes dispatch of Company-owned resources and contracts in each hour of the pro forma year. The pro forma period is July 1, 2009 through June 30, 2010. The model simulates true system operations by evaluating future resource decisions on an hourly basis. Company witness Kalich provides detailed testimony on the AURORA model used by the Company to develop short-term power purchase expense, fuel expense and short-term power sales revenue. His testimony includes a good description of the calculations performed by AURORA.

Q. Did Staff use the same AURORA version and database as Avista for reviewing the Company's proposed power supply costs and for determining Staff's proposed adjustments?

A. Yes, Staff used exactly the same version of AURORA (version 9.3.1001), including the same database used by the Company (North_American_DB_2008-03).[1]

Q. What modifications did Avista make to the database for this case?

A. Avista modified its portfolio of resources to reflect actual operating characteristics, modified natural gas prices to match projected forward prices over the pro forma period, modified regional resource characteristics where better information is known, and replaced Northwest hydro data with Northwest Power Pool data.

Q. Do you accept the modifications made by Avista for this case?

A. I accept the Company's modifications to its own and to other regional resources to better reflect actual operating characteristics. I also accept replacement of Northwest hydro data with Northwest Power Pool data. However, I do not accept the natural gas prices used by Avista for the pro forma period.

Q. What natural gas prices did Avista use for the pro forma period for its AURORA analysis?

A. The natural gas prices used by the Company for this filing are based on a three-month average from

[1]In the testimony of Avista witness Kalich, he erroneously stated that Avista used AURORA version 9.1.1003. The Company actually used version 9.3.1001.

September 1, 2008 to November 30, 2008, of monthly forward prices for the pro forma period.

Q. What gas prices did you use for your analysis?

A. I used a one-month average from March 27, 2009 to April 27, 2009, of monthly natural gas forward prices for the pro forma period. In other words, I averaged 30 forward prices (one each day) for each month for a 12-month period. I chose to use a one-month average of prices because they were the most recent available at the time I performed the AURORA analysis.

Q. Why do you believe that the natural gas prices you used are better than those used by Avista?

A. The prices used by Avista were reasonable at the time the Company conducted its analysis and prepared its case. However, forward gas prices have dropped dramatically since that time. Exhibit No. 101 shows a history of natural gas forward prices since January 2007. Each separate line in the chart represents one month of the pro forma period. In addition to gas forwards, I have also shown forecasted prices from the U.S. Department of Energy's Energy Information Administration (EIA), prepared since January 2008 in its monthly Short Term Energy Outlook reports. Note that EIA's forecasted prices closely track gas forward prices. As indicated by the chart, prices peaked last summer, but have dropped steadily since then. In preparing its case, Avista used an average of prices bounded by the wide pair of bold vertical lines (Sept 08 - Nov 08) shown on the graph in Exhibit No. 101. I used an average of prices bounded by the narrow pair of vertical lines on the right side of the graph. A numerical comparison between Avista's prices and those that I used is shown in Exhibit No. 102 for various trading hubs included in the AURORA modeling. Exhibit No. 103 shows a comparison of monthly prices for the pro forma period for specific gas-fired plants owned by Avista.

I believe the prices I used for my analysis are a much better indication of natural gas prices likely to occur during the pro forma period. The pro forma period begins in July 2009, just two months from the time this testimony is being prepared. Prices obtained two months before the start of the pro forma period are much more likely to be representative than prices obtained 7-10 months before the pro forma period, especially if the change in prices has been continuous and steady over the past 10 months as shown in Exhibit No. 101.

Q. Please explain what a forward price is.

A. A forward price is a price quote to deliver gas at some future date at a price agreed upon today. They are not a forecast of what prices are expected to be at some future time, instead, they are the actual prices at which gas can be purchased now for delivery in the future.

Q. Current natural gas prices are extremely low compared to prices seen over the past several years. Why are you proposing to use lower prices for computing Avista's power supply costs rather than the higher prices of the past?

A. For most ratemaking purposes, adjustments are made to a specific test period to normalize power supply expenses for normal weather and hydroelectric generation and to reflect known and measurable changes for the pro forma period that rates will be in effect. Adjustments are also made to reflect contract changes from the test period to the pro forma period. In the case of natural gas fuel, however, historic averages or test period actual costs are not necessarily a good approximation of costs that will likely be incurred in the future pro forma period. Consequently, natural gas fuel costs are now usually based on forecasts of what those costs are expected to be during the time when new rates will be in effect. They are not historic, nor are they known and measurable in the traditional sense. The gas prices I have used for my AURORA analysis are the prices I expect to occur during the period in which the rates set in this case will be in effect.

While it is true that natural gas prices are currently at six-year lows, it is also true that the prices I used in my analysis are the actual prices at which gas can be purchased now for delivery in the pro forma period. Obviously, Avista will not purchase now all of the gas it expects to need during the pro forma period, but I believe forward prices over the course of the past month are the best information currently available to predict prices that Avista will pay for gas to be used during the pro forma period.

Q. Besides natural gas prices, have you made any additional changes to the AURORA input data used by Avista?

A. Yes, I have. Since its last general rate case in 2008, Avista has included the actual term power and natural gas transactions already entered into for delivery in the pro forma period. Term transactions are monthly and quarterly transactions made less than 18 months prior to delivery. Avista contends that term transactions should be included to more accurately reflect the actual power supply expense the Company will incur during the pro forma period. As of November 30, 2008, Avista had entered into 33 forward electric contracts and forward natural gas contracts for delivery in the pro forma period. The electric contracts include 15 physical purchases and 4 physical sales and 14 financial (fixed-for-floating swaps) purchases. The natural gas transactions include 4 purchases and 4 sales. As Mr. Johnson explained in his testimony, Avista added the physical electric transactions as resources and obligations in the AURORA model and included a mark-to-model adjustment in the pro forma for the financial electric and natural gas transactions. If the actual transactions lower power supply expense (lower purchase costs or higher sales revenue) as compared to the cost produced by the AURORA model, then the lower cost is included in the pro forma expense. If the actual transactions increase power supply expense (higher purchase costs or lower sales revenue) as compared to the cost produced by the AURORA model, then the higher cost is included in the pro forma expense.

Q. What was the effect of Avista including term transactions in calculating its pro forma power supply expense?

A. Because many of the actual transactions included by Avista as pro forma expenses were entered into during the period of high forward prices during the middle of 2008, and because prices have declined substantially since July 2008, the overall impact of the actual transactions is an increase in the pro forma expense. Overall, the actual transactions increase pro forma expense by

$4,314,400 on a system basis, ($1,527,729 Idaho allocation) compared to what expenses would be based solely on the AURORA model output.

Q. Why did you exclude term transactions from your analysis?

A. I excluded all term transactions because I do not believe that they represent normal conditions upon which rates should be based. They are generally made to balance loads and resources in the short-term, usually in response to expectations about short-term conditions like water and weather conditions. Term transactions can be either purchases or sales, and either physical or financial trades. They are the primary element of the utility's hedging strategy. Term transactions made during one certain time period are highly unlikely to be repeated again exactly, both in terms of price, quantity, and proportion of purchases versus sales. In my opinion they in no way represent normal conditions and are not appropriate to include as a basis for setting base rates in a general rate case.

Q. If you remove all term transaction from the power supply cost analysis in this rate case, where do you propose they be considered instead?

A. The proper place to account for actual term transaction is in the Company's Power Cost Adjustment

(PCA) mechanism. Term transactions create real costs that the Company is obligated to pay or real revenues that the Company is entitled to receive. The PCA allows them to do so on an annual basis (as opposed to a long-term basis), subject to the 90/10 sharing percentage now in place.[2]

Q. Have term transactions ever been included in the analysis to compute power supply costs for inclusion in base rates?

A. No, they have not, not for Avista or for any other electric utility within the Commission's jurisdiction. Avista's proposal to include them now would be a significant departure from past practice.

Q. Please summarize the results of your AURORA analysis using your adjusted natural gas prices and after removing all term transactions.

A. The results of my AURORA analysis are shown in Exhibit No. 104. This compares to the Company's AURORA results as presented in Exhibit No. 5 of Mr. Kalich. My results show an annual cost that is $20.6 million less than the Company's result. To these results, resource and contract revenues and expenses not accounted for in AURORA (e.g., fixed costs) must be added to determine net power supply expense.

[2]Avista has requested to change the PCA sharing percentage to 95/5 in this general rate case.

Q. Please explain how your AURORA results are used to make a pro forma adjustment to power supply expense.

A. As explained by Avista witness Johnson, "The pro forma adjustment to power supply expense involves the determination of revenues and expenses based on the generation and dispatch of Company resources and expected wholesale market power prices as determined by the AURORA model simulation for the pro forma period under normal weather and hydro generation conditions. In addition, adjustments are made to reflect contract changes between the test period and the pro forma period." My Exhibit No. 105 shows total net power supply expense during the test period and the pro forma period under both Avista's and Staff's proposals. For information purposes only, the power supply expense currently in rates, which is based on a 2009 calendar year pro forma period, is also shown.

As shown on Exhibit No. 105, current rates are based on a system power supply cost of $174,849,000. Avista's test year power supply expenses were $180,395,000. Avista proposes to adjust test year power supply expenses upward by $27,645,000 to arrive at a pro forma period power supply expense of $208,040,000 on a system basis ($180,395,000 + $27,645,000 = $208,040,000). This represents an increase of $33,191,000 on a system basis over the amount currently built into rates.

Staff, on the other hand, proposes to decrease test year power supply expenses by $13,000,000 to arrive at a pro forma period power supply expense of $167,395,000 on a system basis ($180,395,000 - $13,000,000 = $167,395,000). This represents a decrease of $7,454,000 on a system basis from the amount currently built into rates.

The Idaho allocation of Avista's proposed adjustment to test period expenses is an increase of $9,789,095. Under Staff's proposal, the Idaho allocation of its proposed adjustment to test period expenses is a decrease of $4,603,300. The overall difference between the Company's proposed power supply cost and Staff's is $40,645,000 on a total system basis.

Q. Is it unusual in a rate case to have a difference of over $40 million between the utility's and Staff's recommended power supply costs?

A. Yes, it is an unusually large difference. However, as I explained previously, the change in natural gas price that occurred between when the Company prepared its case and when Staff prepared its case is highly unusual. In addition, Avista included term transactions in its case, which neither Avista nor any other Idaho utility has ever done before. These two differences between Avista's and Staff's case account for the <u>entire</u>

$40 million difference in recommended power supply costs.

Q. Please summarize your recommended changes in power supply cost.

A. My recommended changes to power supply costs are shown in Exhibit No. 106. I have compared my recommended costs with those recommended by Avista witness Johnson. I have highlighted those cost items in which my recommendation differs from the Company's. With only three exceptions, all of my proposed adjustments are based directly on AURORA results. The three exceptions are for the Priest River Project, the Black Creek Index purchase, and the Nichols Pumping sale. Each of these three contracts has a pricing structure that is tied to electric market prices. Because electric market prices are projected in AURORA, I have adjusted these contract costs and revenues to be consistent with prices in AURORA. Exhibit No. 107 shows the computations of these adjustments using my AURORA results along with the adjusted workpapers of Avista witness Johnson.

Q. With the exception of the changes you previously discussed related to gas prices and the removal of all term transactions, do you accept all of the other normalizing and pro forma adjustments to the October 2007 through September 2008 test period power supply revenues and expenses proposed by Avista in this case?

A. Yes, I do. All of the other adjustments proposed by Avista are reasonable and in accordance with adjustments accepted by this Commission in the Company's prior general rate case.

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

A. Yes, it does.

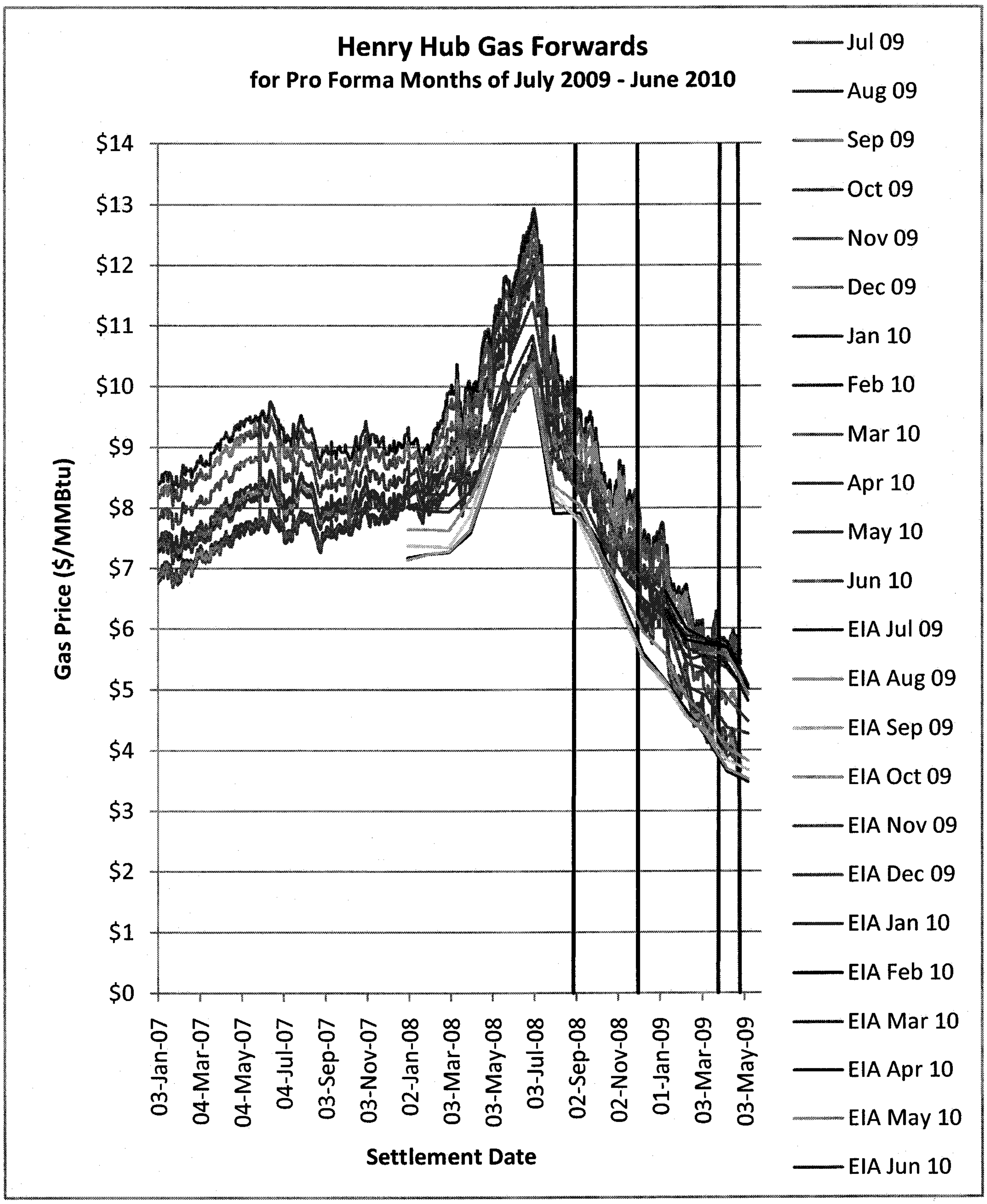

Exhibit No. 101
Case No. AVU-E-9-09-1/
AVU-G-09-1
R. Sterling, Staff
05/29/09

Pro Forma Natural Gas Prices
($/MMBtu)

Basin	Avista	Staff
AECO	7.31	4.27
Malin	7.75	4.60
Spokane	8.03	4.75
Rockies	5.59	3.81
Stanfield	7.67	4.52
Sumas	7.83	4.60
Henry Hub	8.08	5.05
Topock	7.49	4.46

Avista's prices are based on an average of forward prices for the period 8/1/08-11/30/08.
Staff's prices are based on an average of forward prices for the period 3/27/09-4/27/09.

Dispatch Model Prices Summary

	Avista			Staff		
Gas Price Period	8/1/08 - 11/30/08			3/27/09 - 4/27/09		
Month	CSII & Rathdrum Gas ($/dth)	NE/BP/ KFCT Gas ($/dth)	Mid-C ($/MWh)	CSII & Rathdrum Gas ($/dth)	NE/BP/ KFCT Gas ($/dth)	Mid-C ($/MWh)
Jul-09	7.18	7.51	57.01	3.36	3.54	31.44
Aug-09	7.29	7.63	63.09	3.48	3.67	36.05
Sep-09	7.29	7.64	60.64	3.55	3.74	33.56
Oct-09	7.34	7.68	55.47	3.70	3.90	33.13
Nov-09	7.75	8.11	59.58	4.36	4.58	37.45
Dec-09	8.13	8.50	71.66	4.98	5.23	48.21
Jan-10	8.38	8.76	67.51	5.21	5.47	44.84
Feb-10	8.36	8.74	62.47	5.24	5.50	41.42
Mar-10	8.12	8.50	57.69	5.15	5.40	38.17
Apr-10	7.41	7.76	49.74	5.01	5.26	37.45
May-10	7.36	7.70	39.36	5.06	5.31	30.97
Jun-10	7.44	7.79	34.74	5.17	5.43	27.61
Average	**7.67**	**8.03**	**56.58**	**4.52**	**4.75**	**36.69**

CSII	Coyote Springs II
NE	Northeast
BP	Boulder Park
KFCT	Kettle Falls Combustion Turbine

Exhibit No. 103
Case No. AVU-E-9-09-1/
AVU-G-09-1
R. Sterling, Staff
05/29/09

Dispatch Model Pro Forma Costs ($000)
Staff Adjusted

1		Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2	**Hydro Projects**													
3	Clark Fork	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Cabinet Gorge	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Noxon Rapids	0	0	0	0	0	0	0	0	0	0	0	0	0
6	*TOTAL*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
7														
8	Spokane River	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Little Falls	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Long Lake	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Monroe Street	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Nine Mile	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Post Falls	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Upper Falls	0	0	0	0	0	0	0	0	0	0	0	0	0
15	*TOTAL*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
16														
17	Mid-Columbia- Contracts													
18	Priest Rapids	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Rocky Reach	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Wanapum	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Wells	0	0	0	0	0	0	0	0	0	0	0	0	0
22	*TOTAL*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
23														
24	**Thermals**													
25	Boulder Park	36	0	2	0	1	9	0	12	11	0	0	0	0
26	Colstrip	18,030	1,717	1,573	1,727	1,552	1,007	1,038	1,558	1,598	1,548	1,587	1,549	1,575
27	Coyote Springs 2	46,030	5,050	4,868	5,179	3,543	1,864	2,498	3,154	3,533	3,382	3,660	4,249	5,049
28	Kettle Falls	10,907	1,232	1,173	1,295	305	0	0	1,127	1,170	1,127	1,169	1,135	1,173
29	Kettle Falls CT	78	6	9	2	9	16	5	14	13	0	0	2	1
30	Lancaster	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Northeast	43	0	0	0	0	0	0	20	23	0	0	0	0
32	Rathdrum	281	0	6	0	1	50	2	121	100	0	0	1	0
33	*TOTAL*	*75,405*	*8,006*	*7,632*	*8,204*	*5,409*	*2,946*	*3,543*	*6,007*	*6,448*	*6,058*	*6,417*	*6,937*	*7,799*
34														
35	*RESOURCE TOTAL*	*75,405*	*8,006*	*7,632*	*8,204*	*5,409*	*2,946*	*3,543*	*6,007*	*6,448*	*6,058*	*6,417*	*6,937*	*7,799*
36														
37	**Contracts**													
38	Black Creek	89	0	0	0	0	0	0	0	0	0	89	0	0
39	DOPD	783	45	41	62	82	119	126	92	66	37	44	34	35
40	Market Contract 1	7,556	642	580	642	621	642	621	642	642	621	642	621	642
41	Can Ent Return	0	0	0	0	0	0	0	0	0	0	0	0	0
42	Grant County	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Clark Fork LLC	101	8	8	8	13	16	15	11	6	3	3	5	7
44	Market Contract 2	20,192	1,715	1,549	1,715	1,660	1,715	1,660	1,715	1,715	1,660	1,715	1,660	1,715
45	Grant Displacement	5,449	397	385	384	504	522	431	516	438	434	454	473	510
46	Stimson Lumber	2,084	191	182	161	148	144	139	181	198	187	178	193	182
47	Jim Ford Creek	228	39	49	38	33	19	9	0	0	0	1	11	30
48	John Day Creek	81	4	2	2	3	11	14	12	8	6	5	8	6
49	Meyers Falls	409	36	41	50	49	51	46	24	12	14	23	30	32
50	Nichols Pumping	(2,169)	(225)	(188)	(192)	(182)	(156)	(134)	(158)	(181)	(163)	(166)	(182)	(242)
51	Colstrip Start Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
52	PGE CapExch	0	0	0	0	0	0	0	0	0	0	0	0	0
53	Phillips Ranch	1	0	0	0	0	0	0	0	0	0	0	0	0
54	Potlatch	0	0	0	0	0	0	0	0	0	0	0	0	0
55	Wind Contract	2,933	258	201	302	265	256	304	245	246	206	229	236	185
56	Load Following Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0
57	Sheep Creek	317	22	24	34	41	38	34	29	18	16	17	21	23
58	Upriver	2,090	271	266	265	255	250	191	66	(40)	28	105	169	263
59	WNP-3	14,347	2,963	2,676	1,463	1,415	0	0	0	0	0	0	2,867	2,963
60	ST Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
61	ST Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
62	SMUD	(5,264)	(145)	(120)	(152)	(162)	(457)	(599)	(682)	(631)	(597)	(590)	(564)	(567)
63	Thompson River Co-Gen	0	0	0	0	0	0	0	0	0	0	0	0	0
64	*TOTAL*	*49,225*	*6,220*	*5,696*	*4,781*	*4,746*	*3,170*	*2,856*	*2,693*	*2,497*	*2,452*	*2,749*	*5,583*	*5,781*
65														
66	**Market Transactions**													
67	Market Purchases	35,598	5,371	3,348	2,518	1,676	471	323	1,228	4,582	3,206	4,117	3,895	4,862
68	Market Sales	(34,537)	(1,631)	(1,751)	(3,244)	(4,587)	(5,251)	(6,494)	(4,492)	(776)	(1,055)	(1,091)	(2,062)	(2,103)
69	*TOTAL*	*1,060*	*3,741*	*1,597*	*(726)*	*(2,910)*	*(4,780)*	*(6,171)*	*(3,265)*	*3,806*	*2,151*	*3,026*	*1,833*	*2,760*
70														
71	*Fuel and Market Only*	76,465	11,747	9,228	7,478	2,499	(1,834)	(2,628)	2,743	10,254	8,209	9,443	8,770	10,558
72														
73	**Adjustments**													
74	Coyote Springs 2 Start Fuel	45	1	0	0	1	10	29	4	0	0	0	0	0
75	Rathdrum Start Fuel	21	0	1	0	0	3	0	9	7	0	0	0	0
76	Lancaster Start Fuel	0	0	0	0	0	0	0	0	0	0	0	0	0
77	Northeast Lost Margin	10	0	3	0	1	3	0	(0)	1	0	0	1	0
78	Coyote Springs 2 Fuel Cost	(1,529)	(95)	(91)	(82)	(125)	(65)	(84)	(177)	(202)	(156)	(105)	(187)	(161)
79	Lancaster Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
80	**Total Adjustments**	**(1,453)**	**(94)**	**(86)**	**(82)**	**(123)**	**(48)**	**(55)**	**(164)**	**(195)**	**(156)**	**(105)**	**(186)**	**(161)**
81														
82	**Adjusted Fuel & Market**	**75,012**	**11,653**	**9,142**	**7,396**	**2,375**	**-1,882**	**-2,683**	**2,579**	**10,059**	**8,053**	**9,338**	**8,584**	**10,398**

Exhibit No. 104
Case No. AVU-E-9-09-1/
AVU-G-09-1
R. Sterling, Staff

Dispatch Model Pro Forma Generation (aMW)
Staff Adjusted

1		Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2	**Hydro Projects**													
3	Clark Fork	325.9	246.0	284.9	236.2	367.2	648.5	681.2	450.7	244.4	166.9	140.8	166.3	275.8
4	Cabinet Gorge	125.3	100.4	118.0	98.2	148.7	226.3	228.3	178.1	99.9	67.9	58.0	68.2	111.3
5	Noxon Rapids	200.6	145.6	167.0	137.9	218.5	422.2	452.9	272.7	144.4	99.0	82.8	98.1	164.6
6	***TOTAL (aMW)***	***325.9***	***246.0***	***284.9***	***236.2***	***367.2***	***648.5***	***681.2***	***450.7***	***244.4***	***166.9***	***140.8***	***166.3***	***275.8***
7														
8	Spokane River	125.6	138.4	143.5	158.7	169.1	167.9	155.6	98.8	55.0	77.3	95.9	119.0	130.4
9	Little Falls	23.5	27.4	27.9	30.6	32.4	32.2	29.6	17.5	9.7	13.0	16.3	21.5	24.0
10	Long Lake	58.7	66.5	67.1	75.4	82.7	83.3	74.7	43.9	25.4	33.2	40.9	52.8	59.5
11	Monroe Street	11.7	11.9	12.6	13.4	13.6	13.6	13.2	10.6	5.9	9.4	11.2	12.2	12.6
12	Nine Mile	13.3	13.7	15.4	16.7	17.7	16.6	16.2	11.2	5.8	8.3	10.9	13.2	14.5
13	Post Falls	9.8	10.3	11.5	13.4	13.7	13.5	12.9	7.1	2.8	5.3	7.3	9.9	10.4
14	Upper Falls	8.6	8.7	9.0	9.2	8.9	8.7	9.0	8.5	5.4	8.2	9.2	9.3	9.4
15	***TOTAL (aMW)***	***125.6***	***138.4***	***143.5***	***158.7***	***169.1***	***167.9***	***155.6***	***98.8***	***55.0***	***77.3***	***95.9***	***119.0***	***130.4***
16														
17	Mid-Columbia- Contracts	101.7	126.1	102.3	81.5	96.5	104.0	119.3	128.2	99.8	77.4	87.5	91.7	105.6
18	Priest Rapids	19.2	30.6	25.3	19.1	17.5	12.7	18.5	14.4	13.9	12.4	13.9	24.5	28.4
19	Rocky Reach	20.3	25.8	19.7	16.1	21.8	22.4	26.5	25.1	21.5	14.0	15.7	16.6	18.8
20	Wanapum	27.5	27.4	23.3	18.8	22.9	26.7	29.9	46.8	27.7	27.1	31.0	22.2	26.1
21	Wells	34.6	42.3	33.9	27.4	34.2	42.1	44.5	41.9	36.7	23.9	26.9	28.4	32.3
22	***TOTAL (aMW)***	***101.7***	***126.1***	***102.3***	***81.5***	***96.5***	***104.0***	***119.3***	***128.2***	***99.8***	***77.4***	***87.5***	***91.7***	***105.6***
23														
24	***TOTAL***	***553.2***	***510.5***	***530.7***	***476.3***	***632.8***	***920.4***	***956.1***	***677.8***	***399.1***	***321.6***	***324.2***	***377.0***	***511.8***
25														
26	**Thermals**													
27	Boulder Park	0.1	0.0	0.1	0.0	0.0	0.2	0.0	0.5	0.4	0.0	0.0	0.0	0.0
28	Colstrip	189.7	203.4	206.3	204.6	189.9	119.3	127.1	200.8	205.9	206.2	204.4	206.2	202.9
29	Coyote Springs 2	169.3	185.0	197.6	194.1	140.7	71.0	96.0	180.5	195.6	190.2	193.8	194.1	194.1
30	Kettle Falls	34.4	40.8	43.1	43.0	10.5	0.0	0.0	44.4	46.2	45.9	46.1	46.3	46.3
31	Kettle Falls CT	0.2	0.2	0.3	0.1	0.3	0.5	0.1	0.6	0.5	0.0	0.0	0.1	0.0
32	Lancaster	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Northeast	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.0	0.0	0.0	0.0
34	Rathdrum	0.8	0.0	0.2	0.0	0.0	1.2	0.0	4.3	3.3	0.0	0.0	0.0	0.0
35	***TOTAL***	***394.6***	***429.4***	***447.5***	***441.8***	***341.4***	***192.1***	***223.3***	***431.7***	***452.6***	***442.3***	***444.3***	***446.7***	***443.4***
36														
37	***RESOURCE TOTAL***	***947.8***	***939.9***	***978.2***	***918.2***	***974.1***	***1,112.6***	***1,179.4***	***1,109.5***	***851.7***	***763.8***	***768.5***	***823.6***	***955.2***
38														
39	**Contracts**													
40	Black Creek	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.4	0.0	0.0
41	DOPD	3.7	2.4	2.4	3.3	4.8	6.7	7.3	5.3	3.8	2.0	2.4	2.0	1.8
42	Market Contract 1	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
43	Can Ent Return	(3.9)	(3.5)	(3.6)	(3.7)	(3.6)	(3.5)	(3.6)	(4.2)	(4.0)	(4.1)	(4.2)	(4.0)	(4.2)
44	Grant County	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Clark Fork LLC	0.1	0.1	0.1	0.1	0.2	0.3	0.3	0.2	0.1	0.1	0.0	0.1	0.1
46	Market Contract 2	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
47	Grant Displacement	22.2	17.4	17.6	17.7	26.2	31.8	31.6	27.6	19.7	19.0	18.7	19.3	19.2
48	Stimson Lumber	4.2	4.2	4.4	4.5	4.3	4.0	4.0	4.0	4.4	4.3	4.0	4.5	4.0
49	Jim Ford Creek	0.4	0.6	0.8	1.2	1.0	0.6	0.3	0.0	0.0	0.0	0.0	0.2	0.4
50	John Day Creek	0.2	0.1	0.0	0.1	0.1	0.4	0.6	0.4	0.3	0.2	0.2	0.1	0.1
51	Meyers Falls	1.0	1.0	1.2	1.4	1.4	1.4	1.3	0.7	0.3	0.4	0.6	0.9	0.9
52	Nichols Pumping	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)	(7.8)
53	Colstrip Start Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	PGE CapExch	0.1	2.4	0.0	(2.8)	(0.4)	1.2	0.0	(0.8)	0.8	(0.4)	0.4	1.7	(0.8)
55	Phillips Ranch	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
56	Potlatch	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
57	Wind Contract	8.4	8.6	7.4	10.0	9.1	8.5	10.4	8.3	8.3	7.2	7.8	8.3	6.3
58	Load Following Contracts	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
59	Sheep Creek	0.8	0.4	0.6	1.1	1.5	1.6	1.6	1.0	0.3	0.2	0.3	0.5	0.4
60	Upriver	6.1	8.3	9.0	10.4	10.3	9.8	7.8	2.0	(1.2)	0.9	3.2	5.4	8.0
61	WNP-3	43.8	106.6	106.6	52.6	52.6	0.0	0.0	0.0	0.0	0.0	0.0	106.6	106.6
62	ST Purchases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
63	ST Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
64	SMUD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
65	Thompson River Co-Gen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	***TOTAL***	***179.8***	***240.8***	***238.9***	***188.1***	***199.8***	***155.2***	***153.7***	***136.8***	***125.1***	***122.0***	***130.1***	***237.6***	***235.3***
67														
68	**Market Transactions**													
69	Market Purchases	92.0	142.5	105.9	77.9	50.3	13.0	11.9	39.3	138.6	116.5	154.6	129.8	123.1
70	Market Sales	(135.7)	(55.5)	(70.3)	(126.2)	(191.6)	(287.3)	(378.4)	(227.3)	(35.6)	(53.8)	(48.6)	(86.7)	(66.3)
71	***TOTAL***	***(43.7)***	***87.0***	***35.6***	***(48.3)***	***(141.2)***	***(274.3)***	***(366.5)***	***(188.0)***	***103.0***	***62.6***	***106.1***	***43.1***	***56.8***
72														
73	***System Load***	***1,083.9***	***1,267.7***	***1,252.7***	***1,057.9***	***1,032.7***	***993.4***	***966.6***	***1,058.3***	***1,079.8***	***948.4***	***1,004.7***	***1,104.4***	***1,247.3***

Exhibit No. 104
Case No. AVU-E-9-09-1/
AVU-G-09-1
R. Sterling, Staff
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Dispatch Model Generation (GWh)
Staff Adjusted

1		Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2	**Hydro Projects**													
3	Clark Fork	2,854.5	183.0	191.5	175.7	264.4	482.5	490.5	335.4	181.8	120.1	104.8	119.7	205.2
4	Cabinet Gorge	1,097.6	74.7	79.3	73.1	107.1	168.4	164.4	132.5	74.4	48.9	43.2	49.1	82.8
5	Noxon Rapids	1,756.9	108.3	112.2	102.6	157.3	314.1	326.1	202.9	107.4	71.2	61.6	70.6	122.4
6	***TOTAL***	***2,854.5***	***183.0***	***191.5***	***175.7***	***264.4***	***482.5***	***490.5***	***335.4***	***181.8***	***120.1***	***104.8***	***119.7***	***205.2***
7														
8	Spokane River	1,100.3	103.0	96.4	118.1	121.7	125.0	112.0	73.5	40.9	55.7	71.3	85.7	97.0
9	Little Falls	205.4	20.4	18.7	22.7	23.3	24.0	21.3	13.0	7.2	9.3	12.1	15.4	17.9
10	Long Lake	514.2	49.4	45.1	56.1	59.6	62.0	53.8	32.7	18.9	23.9	30.4	38.0	44.3
11	Monroe Street	102.3	8.8	8.5	10.0	9.8	10.1	9.5	7.9	4.4	6.7	8.3	8.8	9.4
12	Nine Mile	116.8	10.2	10.4	12.4	12.8	12.4	11.7	8.3	4.3	6.0	8.1	9.5	10.8
13	Post Falls	86.0	7.7	7.7	10.0	9.9	10.0	9.3	5.3	2.0	3.8	5.4	7.2	7.7
14	Upper Falls	75.5	6.5	6.1	6.9	6.4	6.5	6.5	6.3	4.0	5.9	6.9	6.7	7.0
15	***TOTAL***	***1,100.3***	***103.0***	***96.4***	***118.1***	***121.7***	***125.0***	***112.0***	***73.5***	***40.9***	***55.7***	***71.3***	***85.7***	***97.0***
16														
17	Mid-Columbia- Contracts	890.9	93.8	68.7	60.6	69.5	77.4	85.9	95.4	74.3	55.7	65.1	66.0	78.5
18	Priest Rapids	168.6	22.7	17.0	14.2	12.6	9.5	13.3	10.7	10.4	8.9	10.3	17.7	21.1
19	Rocky Reach	178.1	19.2	13.3	12.0	15.7	16.7	19.1	18.7	16.0	10.1	11.6	11.9	14.0
20	Wanapum	241.3	20.4	15.7	14.0	16.5	19.9	21.5	34.8	20.6	19.5	23.1	16.0	19.4
21	Wells	303.0	31.5	22.8	20.4	24.6	31.3	32.0	31.2	27.3	17.2	20.0	20.5	24.0
22	***TOTAL***	***890.9***	***93.8***	***68.7***	***60.6***	***69.5***	***77.4***	***85.9***	***95.4***	***74.3***	***55.7***	***65.1***	***66.0***	***78.5***
23														
24	***TOTAL***	***4,845.8***	***379.8***	***356.6***	***354.4***	***455.6***	***684.8***	***688.4***	***504.3***	***297.0***	***231.5***	***241.2***	***271.4***	***380.8***
25														
26	**Thermals**													
27	Boulder Park	1.0	0.0	0.0	0.0	0.0	0.2	0.0	0.4	0.3	0.0	0.0	0.0	0.0
28	Colstrip	1,661.8	151.4	138.6	152.2	136.8	88.7	91.5	149.4	153.2	148.4	152.1	148.5	151.0
29	Coyote Springs 2	1,483.2	137.6	132.8	144.4	101.3	52.8	69.1	134.3	145.5	136.9	144.2	139.8	144.4
30	Kettle Falls	301.3	30.3	29.0	32.0	7.5	0.0	0.0	33.0	34.3	33.1	34.3	33.3	34.4
31	Kettle Falls CT	1.9	0.1	0.2	0.1	0.2	0.4	0.1	0.4	0.4	0.0	0.0	0.1	0.0
32	Lancaster	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Northeast	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.5	0.0	0.0	0.0	0.0
34	Rathdrum	6.7	0.0	0.1	0.0	0.0	0.9	0.0	3.2	2.5	0.0	0.0	0.0	0.0
35	***TOTAL***	***3,456.8***	***319.5***	***300.7***	***328.7***	***245.8***	***142.9***	***160.8***	***321.2***	***336.7***	***318.4***	***330.6***	***321.6***	***329.9***
36														
37	***RESOURCE TOTAL***	***8,302.6***	***699.3***	***657.4***	***683.1***	***701.4***	***827.7***	***849.2***	***825.5***	***633.7***	***549.9***	***571.8***	***593.0***	***710.6***
38														
39	**Contracts**													
40	Black Creek	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	0.0	0.0
41	DOPD	32.3	1.8	1.6	2.4	3.5	5.0	5.3	3.9	2.8	1.5	1.8	1.4	1.4
42	Market Contract 1	219.0	18.6	16.8	18.6	18.0	18.6	18.0	18.6	18.6	18.0	18.6	18.0	18.6
43	Can Ent Return	(33.8)	(2.6)	(2.4)	(2.7)	(2.6)	(2.6)	(2.6)	(3.1)	(3.0)	(3.0)	(3.1)	(2.9)	(3.1)
44	Grant County	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Clark Fork LLC	1.2	0.1	0.1	0.1	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.1
46	Market Contract 2	657.0	55.8	50.4	55.8	54.0	55.8	54.0	55.8	55.8	54.0	55.8	54.0	55.8
47	Grant Displacement	194.2	13.0	11.8	13.1	18.8	23.7	22.8	20.5	14.6	13.7	13.9	13.9	14.3
48	Stimson Lumber	37.0	3.1	2.9	3.4	3.1	3.0	2.9	3.0	3.3	3.1	3.0	3.2	3.0
49	Jim Ford Creek	3.7	0.4	0.5	0.9	0.8	0.4	0.2	0.0	0.0	0.0	0.0	0.1	0.3
50	John Day Creek	1.9	0.1	0.0	0.1	0.1	0.3	0.4	0.3	0.2	0.1	0.1	0.1	0.1
51	Meyers Falls	8.4	0.7	0.8	1.0	1.0	1.0	0.9	0.5	0.2	0.3	0.5	0.6	0.7
52	Nichols Pumping	(67.9)	(5.8)	(5.2)	(5.8)	(5.6)	(5.8)	(5.6)	(5.8)	(5.8)	(5.6)	(5.8)	(5.6)	(5.8)
53	Colstrip Start Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	PGE CapExch	0.9	1.8	0.0	(2.1)	(0.3)	0.9	0.0	(0.6)	0.6	(0.3)	0.3	1.2	(0.6)
55	Phillips Ranch	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
56	Potlatch	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
57	Wind Contract	73.2	6.4	5.0	7.5	6.6	6.3	7.5	6.2	6.2	5.2	5.8	6.0	4.7
58	Load Following Contracts	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
59	Sheep Creek	6.9	0.3	0.4	0.8	1.1	1.2	1.1	0.7	0.2	0.2	0.2	0.3	0.3
60	Upriver	53.8	6.2	6.1	7.8	7.4	7.3	5.6	1.5	(0.9)	0.6	2.4	3.9	6.0
61	WNP-3	384.0	79.3	71.6	39.1	37.9	0.0	0.0	0.0	0.0	0.0	0.0	76.7	79.3
62	ST Purchases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
63	ST Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
64	SMUD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
65	Thompson River Co-Gen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	***TOTAL***	***1,575.1***	***179.1***	***160.5***	***139.9***	***143.9***	***115.4***	***110.7***	***101.8***	***93.0***	***87.8***	***96.8***	***171.1***	***175.0***
67														
68	**Market Transactions**													
69	Market Purchases	806.0	106.0	71.2	58.0	36.2	9.7	8.6	29.2	103.1	83.9	115.0	93.5	91.6
70	Market Sales	(1,188.8)	(41.3)	(47.3)	(93.9)	(137.9)	(213.8)	(272.5)	(169.1)	(26.5)	(38.8)	(36.1)	(62.4)	(49.3)
71	***TOTAL***	***(382.8)***	***64.7***	***23.9***	***(36.0)***	***(101.7)***	***(204.1)***	***(263.9)***	***(139.9)***	***76.6***	***45.1***	***78.9***	***31.1***	***42.3***
72														
73	***SYSTEM LOAD***	***9,494.9***	***943.1***	***841.8***	***787.1***	***743.5***	***739.1***	***696.0***	***787.4***	***803.4***	***682.9***	***747.5***	***795.1***	***928.0***

Exhibit No. 104
Case No. AVU-E-9-09-1/
AVU-G-09-1
R. Sterling, Staff
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Power Supply Expense
(Not Including Directly Assigned Potlatch Purchase)

	Avista Proposal		Staff Proposal	
	System	Idaho Allocation	System	Idaho Allocation
Power Supply Expense in Current Base Rates (Calendar 2009 pro forma)	$174,849,000			
Actual Oct 07 - Sept 08 Power Supply Expenses	$180,395,000			
Adjustment to Test Period	$27,645,000	$9,789,095	-$13,000,000	-$4,603,300
July 2009 - June 2010 Pro Forma Power Supply Expense	**$208,040,000**		**$167,395,000**	
Increase/Decrease from Expense in Current Rates	$33,191,000	$11,752,933	-$7,454,000	-$2,639,461

Exhibit No. 105
Case No. AVU-E-9-09-1/
AVU-G-09-1
R. Sterling, Staff
05/29/09

Avista Corp.
Staff Adjusted Power Supply Pro forma - Idaho Jurisdiction
System Numbers - Oct 2007 - Sep 2008 Actual and Jul 09 - Jun 10 Pro forma
No Short-Term Transactions & 3/27/09 - 4/27/09 Gas Prices

			Company Case		Staff Recommendation	
Line No.		Oct 07 - Sep 08 **Actuals**	Adjustment	Jul 09 - Jun 10 **Pro forma**	Adjustment	Jul 09 - Jun 10 **Pro forma**
	555 PURCHASED POWER					
1	Modeled Short-Term Market Purchases	$0	$51,202	$51,202	$35,598	$35,598
2	Actual ST Market Purchases - Physical	148,407	-117,609	30,798	-148,407	0
3	Actual ST Purchases - Financial M-to-M	$0	$2,923	$2,923	$0	0
4	Rocky Reach	2,068	89	2,157	89	2,157
5	Wanapum	5,406	-3,369	2,037	-3,369	2,037
6	Wells, Avista and Colville Share	1,311	11,302	12,613	11,302	12,613
7	Priest Rapids Project	4,858	2,361	7,219	2,143	7,001
8	Grant Displacement	5,552	-219	5,333	-219	5,333
9	Douglas Settlement	497	122	619	122	619
10	WNP-3	12,553	2,248	14,801	2,248	14,801
11	Deer Lake-IP&L	7	0	7	0	7
12	Small Power	1,125	29	1,154	29	1,154
13	Stimson	1,964	138	2,102	138	2,102
14	Spokane-Upriver	1,790	300	2,090	300	2,090
15	Douglas Exchange Capacity	1,648	-1,648	0	-1,648	0
16	Seattle Exchange Capacity	1,699	-1,699	0	-1,699	0
17	Black Creek Index Purchase	144	11	155	-62	82
18	Non-Monetary	-242	242	0	242	0
19	Contract A	6,808	-19	6,789	-19	6,789
20	Contract B	6,764	-19	6,745	-19	6,745
21	Contract C	6,675	-17	6,658	-17	6,658
22	Contract D	7,576	-20	7,556	-20	7,556
23	CS2 Exchange	387	-387	0	-387	0
24	Northwestern Deviation Energy	1,867	-1,867	0	-1,867	0
25	BPA NT Deviation Energy	3,236	-3,236	0	-3,236	0
26	Potlatch Co-Gen Purchase	18,439	-18,439	0	-18,439	0
27	Spinning Reserve Purchase	1,500	0	1,500	0	1,500
28	Ancillary Services	670	-670	0	-670	0
29	Stateline Wind Purchase	3,424	-159	3,265	-159	3,265
30	Total Account 555	246,133	-78,409	167,724	-128,026	118,107
	557 OTHER EXPENSES					
31	Broker Commission Fees	104	0	104	0	104
32	REC Purchases	364	-14	350	-14	350
33	Bad Debt Reserve	2,728	-2,728	0	-2,728	0
34	Natural Gas Fuel Purchases	39,075	-39,075	0	-39,075	0
35	Total Account 557	42,271	-41,817	454	-41,817	454
	501 THERMAL FUEL EXPENSE					
36	Kettle Falls - Wood Fuel	7,227	3,848	11,075	3,680	10,907
37	Kettle Falls - Start-up Gas	23	0	23	0	23
38	Colstrip - Coal	17,688	418	18,106	342	18,030
39	Colstip - Oil	91	111	202	111	202
40	Total Account 501	25,029	4,377	29,406	4,133	29,162
	547 OTHER FUEL EXPENSE					
41	Coyote Springs Gas	99,105	-30,692	68,413	-53,075	46,030
42	Actual Gas Purchases Financial M-to-M	0	1,348	1,348	0	0
43	Gas Transportation Charge	5,961	911	6,872	911	6,872
44	Rathdrum Gas	616	-342	274	-335	281
45	Northeast CT Gas	277	-216	61	-234	43
46	Boulder Park Gas	2,127	-2,090	37	-2,091	36
47	Kettle Falls CT Gas	312	-236	76	-234	78
48	Total Account 547	108,398	-31,316	77,082	-55,058	53,340
	565 TRANSMISSION OF ELECTRICITY BY OTHERS					
49	WNP-3	789	0	789	0	789
50	Sand Dunes-Warden	20	0	20	0	20
51	Black Creek Wheeling	18	2	20	2	20
52	Wheeling for System Sales & Purchases	845	0	845	0	845
53	PTP for Colstrip & Coyote	8,427	3	8,430	3	8,430
54	BPA Townsend-Garrison Wheeling	1,173	0	1,173	0	1,173
55	Avista on BPA - Borderline	1,483	-5	1,478	-5	1,478
56	Kootenai for Worley	39	6	45	6	45
57	Sagle-Northern Lights	136	-2	134	-2	134
58	Garrison-Burke	592	0	592	0	592

Avista Corp.
Staff Adjusted Power Supply Pro forma - Idaho Jurisdiction
System Numbers - Oct 2007 - Sep 2008 Actual and Jul 09 - Jun 10 Pro forma
No Short-Term Transactions & 3/27/09 - 4/27/09 Gas Prices

Line No.		Oct 07 - Sep 08 Actuals	Company Case Adjustment	Company Case Jul 09 - Jun 10 Pro forma	Staff Recommendation Adjustment	Staff Recommendation Jul 09 - Jun 10 Pro forma
59	PGE Firm Wheeling	643	0	643	0	643
60	Total Account 565	14,165	4	14,169	4	14,169
	536 WATER FOR POWER					
61	Headwater Benefits Payments	654	1	655	1	655
	549 MISC OTHER GENERATION EXPENSE					
62	Rathdrum Municipal Payment	175	-15	160	-15	160
63	TOTAL EXPENSE	436,825	-147,175	289,650	-220,778	216,047
	447 SALES FOR RESALE					
64	Modeled Short-Term Market Sales	0	53,641	53,641	34,537	34,537
65	Actual ST Market Sales - Physical	132,119	-119,617	12,502	-132,119	0
66	Peaker (PGE) Capacity Sale	1,800	0	1,800	0	1,800
67	Nichols Pumping Sale	3,440	402	3,842	-950	2,490
68	Sovereign/Kaiser DES	816	-755	61	-755	61
69	Pend Oreille DES & Spinning	555	-165	390	-165	390
70	Northwestern Load Following	5,225	-1,968	3,257	-1,968	3,257
71	SMUD Sale	49,173	-43,331	5,842	-43,331	5,842
72	Ancillary Services	670	-670	0	-670	0
73	Spokane Energy Service Fee - Peaker Sale	-52	0	-52	0	-52
74	BPA NT Deviation Energy	2,073	-2,073	0	-2,073	0
75	Total Account 447	195,819	-114,536	81,283	-147,493	48,326
	456 OTHER ELECTRIC REVENUE					
76	Renewable Energy Credit Sales	13	-13	0	-13	0
77	Gas Not Consumed Sales Revenue	41,799	-41,799	0	-41,799	0
78	Total Account 456	41,812	-41,812	0	-41,812	0
	453 SALES OF WATER AND WATER POWER					
79	Upstream Storage Revenue	303	-1	302	-1	302
	454 MISC RENTS					
80	Colstrip Rents	57	-33	24	-33	24
81	TOTAL REVENUE	237,991	-156,382	81,609	-189,339	48,652
82	TOTAL NET EXPENSE	198,834	9,206	208,040	-31,439	167,395
83	**Potlatch Purchase Assigned to Idaho**		18,439		18,439	
84	**Total Adjustment Including Potlatch**		27,645		-13,000	

Staff Adjustments to Index Contracts

	Total	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
	8760	744	672	743	720	744	720	744	744	720	744	721	744
Modeled Electric Price	$36.69	$44.84	$41.42	$38.17	$37.45	$30.97	$27.61	$31.44	$36.05	$33.56	$33.13	$37.45	$48.21
Sales													
Nichols Pumping													
MWh	67,890	5,766	5,208	5,766	5,580	5,766	5,580	5,766	5,766	5,580	5,766	5,580	5,766
Revenue	$2,490,295	$258,523	$215,727	$220,073	$208,961	$178,553	$154,079	$181,292	$207,889	$187,256	$191,011	$208,980	$277,951
Purchases													
Black Creek, MWh											3,274		
Black Creek Expense	82,266										$82,266		

Priest Rapids Project

	Total	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Market Price		$44.84	$41.42	$38.17	$37.45	$30.97	$27.61	$31.44	$36.05	$33.56	$33.13	$37.45	$48.21
Priest Rapids, MWh	168,599	22,738	17,019	14,240	12,628	9,481	13,349	10,726	10,357	8,919	10,344	17,663	21,137
Wanpum, MWh	143,281	20,382	15,653	13,970	16,510	19,893	21,506	0	0	0	0	15,962	19,405
Meaningful Priority		3.30%	3.30%	3.30%	3.30%	3.30%	3.30%	2.87%	2.87%	2.87%	2.87%	3.30%	3.30%
Surplus		0.99%	0.99%	0.99%	0.99%	0.99%	0.99%	0.00%	0.00%	0.00%	0.00%	1.86%	1.86%
Surplus Conversion		0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.41%	0.41%	0.41%	0.41%	0.24%	0.24%
Avista Total Slice		4.65%	4.65%	4.65%	4.65%	4.65%	4.65%	3.28%	3.28%	3.28%	3.28%	5.40%	5.40%
Grant's Share of Reasonable Portion Revenue		10%	10%	10%	10%	10%	10%						
Meaningful Priority Energy, MWh	220,694	30,601	23,187	20,020	20,679	20,846	24,736	9,385	9,062	7,804	9,051	20,549	24,776
Meaningful Priority Expense	$10,758,243	$1,372,040	$960,446	$764,092	$774,371	$645,527	$683,016	$584,067	$584,067	$584,067	$584,067	$1,611,241	$1,611,241
Reasonable Portion Cost		$571,458	$432,993	$373,849	$386,155	$389,282	$461,916	$76,745	$76,745	$76,745	$76,745	$378,911	$378,911
Reasonable Portion Revenue	$9,077,291	$1,234,836	$864,401	$687,683	$696,934	$580,975	$614,714	$294,549	$294,549	$294,549	$294,549	$1,609,776	$1,609,776
Net Meaningful Priority Cost	$5,361,408	$708,662	$529,038	$450,259	$463,592	$453,834	$530,218	$366,264	$366,264	$366,264	$366,264	$380,376	$380,376
Net Meaningful Priority Cost per MWh	$24.29	$23.16	$22.82	$22.49	$22.42	$21.77	$21.44						
Surplus MWh	67,567	9,180	6,956	6,006	6,204	6,254	7,421	0	0	0	0	11,582	13,965
Project Cost		$18.67	$18.67	$18.67	$18.67	$18.67	$18.67						
Surplus Cost	$1,212,138	$171,437	$129,898	$112,155	$115,846	$116,784	$138,575	$0	$0	$0	$0	$213,721	$213,721
Surplus Cost per MWh	$17.94												
Surplus Conversion MWh	23,620	3,338	2,529	2,184	2,256	2,274	2,698	1,341	1,295	1,115	1,293	1,494	1,802
Project Cost		$18.67	$18.67	$18.67	$18.67	$18.67	$18.67						
Surplus Conversion Cost	$427,491	$62,341	$47,236	$40,784	$42,126	$42,467	$50,391	$21,745	$21,745	$21,745	$21,745	$27,584	$27,584
Surplus Conversion Cost per MWh	$18.10												
Total Priest Rapids Product Cost	$7,001,037	$942,440	$706,172	$603,197	$621,564	$613,086	$719,183	$388,009	$388,009	$388,009	$388,009	$621,681	$621,681
Total Priest Rapids Product Cost per MWh	$22.45												
Total Project Generation and Cost													
Wanapum Total Generation, aMW		582	491	421	491	578	637	560	332	324	373	413	483
Wanapum Total Generation, aMW	4,149,739	432790	330263	312604	353854	430068	458341	416459	246790	233561	277639	298072	359298
Wanapum Total Cost	$82,364,500	$7,517,417	$7,517,417	$7,517,417	$7,517,417	$7,517,417	$7,517,417	$6,210,000	$6,210,000	$6,210,000	$6,210,000	$6,210,000	$6,210,000
Wanapum Total Cost per MWh	$19.85												
Priest Rapids Total Generation, aMW		645	536	427	376	276	391	430	418	373	421	461	527
Priest Rapids Total Generation, MWh	3,852,688	480218	360436	317464	270545	205164	281455	320145	311127	268364	313382	332097	392291
Priest Rapids Total Cost	$67,074,500	$5,925,583	$5,925,583	$5,925,583	$5,925,583	$5,925,583	$5,925,583	$5,253,500	$5,253,500	$5,253,500	$5,253,500	$5,253,500	$5,253,500

Exhibit No. 107
Case No. AVU-E-9-09-1/
AVU-G-09-1
R. Sterling, Staff
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Avista Corp.
Market Purchases and Sales, Plant Generation and Fuel Cost Summary
Staff Adjusted Idaho Pro forma July 2009 - June 2010

	Total	744 Jan-10	672 Feb-10	744 Mar-10	719 Apr-10	744 May-10	720 Jun-10	744 Jul-09	744 Aug-09	720 Sep-09	745 Oct-09	720 Nov-09	744 Dec-09
Market Sales - Dollars	**-$34,537,232**	-$1,630,579	-$1,751,320	-$3,244,175	-$4,586,566	-$5,251,342	-$6,493,898	-$4,492,459	-$776,361	-$1,054,673	-$1,090,973	-$2,062,279	-$2,102,605
Market Sales - MWh	(1,188,804)	-41,262	-47,266	-93,925	-137,943	-213,755	-272,476	-169,108	-26,484	-38,762	-36,126	-62,394	-49,304
Average Market Sales Price -$/ MWh	$29.05	$39.52	$37.05	$34.54	$33.25	$24.57	$23.83	$26.57	$29.31	$27.21	$30.20	$33.05	$42.65
Market Purchases - Dollars	**$35,597,579**	$5,371,485	$3,347,898	$2,518,068	$1,676,136	$471,146	$322,669	$1,227,662	$4,581,937	$3,205,532	$4,117,418	$3,895,414	$4,862,216
Market Purchases - MWh	805,983	106,002	71,185	57,967	36,243	9,690	8,597	29,229	103,124	83,864	115,048	93,451	91,583
Average Market Purchase Price - $/MWh	$44.17	$50.67	$47.03	$43.44	$46.25	$48.62		$42.00	$44.43	$38.22	$35.79	$41.68	$53.09
Net Market Purchases (Sales) MWh	-382,821	64,740	23,919	-35,958	-101,700	-204,065	-263,879	-139,878	76,639	45,102	78,923	31,057	42,279
Net Market Purchases (Sales) aMW	-43.7	87	36	-48	-141	-274	-366	-188	103	63	106	43	57
Average Sale and Purchase Price - $/MWh	**$35.16**	$47.55	$43.05	$37.94	$35.95	$25.61	$24.25	$28.84	$41.34	$34.74	$34.45	$38.23	$49.44
Colstrip MWh	1,661,763	151,364	138,609	152,244	136,762	88,731	91,520	149,383	153,199	148,433	152,102	148,451	150,965
Colstrip Fuel Cost $/MWh	$10.85	$11.35	$11.35	$11.35	$11.35	$11.35	$11.35	$10.43	$10.43	$10.43	$10.43	$10.43	$10.43
Colstrip Fuel Cost	**$18,029,778**	$1,717,454	$1,572,732	$1,727,438	$1,551,777	$1,006,784	$1,038,429	$1,558,355	$1,598,163	$1,548,443	$1,586,717	$1,548,631	$1,574,855
Kettle Falls MWh	301,333	30,334	28,994	31,992	7,528	0	0	33,011	34,338	33,051	34,316	33,330	34,440
Kettle Falls Fuel Cost $/MWh	$36.20	$40.61	$40.47	$40.48	$40.48	#DIV/0!		$34.15	$34.07	$34.08	$34.08	$34.07	$34.07
Kettle Falls Fuel Cost	**$10,907,098**	$1,232,012	$1,173,370	$1,294,990	$304,715	$0	$0	$1,127,329	$1,170,024	$1,126,530	$1,169,316	$1,135,495	$1,173,319
Coyote Springs MWh	1,483,177	137,622	132,793	144,447	101,275	52,806	69,103	134,315	145,532	136,925	144,173	139,751	144,435
Coyote Springs Fuel Cost $/MWh	$31.03	$36.70	$36.66	$35.85	$34.98	$35.31	$36.15	$23.48	$24.28	$24.70	$25.39	$30.40	$34.96
Coyote Springs Fuel Cost	**$46,030,350**	$5,050,082	$4,867,750	$5,179,106	$3,542,644	$1,864,337	$2,498,213	$3,153,940	$3,533,285	$3,382,440	$3,660,382	$4,248,953	$5,049,219
Boulder Park MWh	966	5	48	1	12	183	7	392	309	0	0	9	1
Boulder Park Fuel Cost $/MWh	$37.03	$49.41	$49.68	$48.78	$47.52	$47.96	$49.03	$31.89	$34.04	$34.51		$41.89	$47.29
Boulder Park Fuel Cost	**$35,754**	$238	$2,397	$42	$582	$8,762	$324	$12,495	$10,506	$2	$0	$375	$31
Kettle Falls CT MWh	1,940	128	183	51	192	354	99	443	392	10	4	58	26
Kettle Falls CT Fuel Cost $/MWh	$40.13	$47.91	$48.17	$47.30	$46.08	$46.50	$47.54	$30.89	$32.59	$33.38	$33.84	$40.24	$46.73
Kettle Falls CT Fuel Cost	**$77,839**	$6,117	$8,835	$2,403	$8,865	$16,475	$4,688	$13,677	$12,762	$329	$129	$2,348	$1,210
Rathdrum MWh	6,681	2	108	0	10	859	26	3,187	2,470	3	0	16	1
Rathdrum Fuel Cost $/MWh	$42.04	$59.40	$59.73		$57.11	$57.64	$58.94	$38.12	$40.59	$41.30		$49.96	$56.80
Rathdrum Fuel Cost	**$280,821**	$114	$6,431	$0	$566	$49,502	$1,526	$121,486	$100,250	$115	$0	$787	$44
Northeast MWh	920	0	0	0	0	2	0	443	475	0	0	0	0
Northeast Fuel Cost $/MWh	$47.00					$68.15		$45.32	$48.49				
Northeast Fuel Cost	**$43,224**	$0	$0	$0	$0	$111	$0	$20,061	$23,051	$0	$0	$0	$0
Total Fuel Expense	**$75,404,864**	$8,006,017	$7,631,516	$8,203,979	$5,409,148	$2,945,971	$3,543,181	$6,007,343	$6,448,040	$6,057,859	$6,416,544	$6,936,589	$7,798,678

Net Fuel and Purchase Expense	**$76,465,211**

Exhibit No. 107
Case No. AVU-E-9-09-1/
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R. Sterling, Staff
05/29/09 Page 2 of 2

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 29TH DAY OF MAY 2009, SERVED THE FOREGOING **DIRECT TESTIMONY OF RICK STERLING**, IN CASE NOS. AVU-E-09-1 & AVU-G-09-1, BY ELECTRONIC MAIL TO THE FOLLOWING:

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