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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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-10-01

DIRECT TESTIMONY
OF
WILLIAM G. JOHNSON

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

Q. Please state your name, business address, and present position with Avista Corporation.

A. My name is William G. Johnson. My business address is 1411 East Mission Avenue, Spokane, Washington, and I am employed by the Company as a Wholesale Marketing Manager in the Energy Resources Department.

Q. What is your educational background?

A. I graduated from the University of Montana in 1981 with a Bachelor of Arts Degree in Political Science/Economics. I obtained a Master of Arts Degree in Economics from the University of Montana in 1985.

Q. How long have you been employed by the Company and what are your duties as a Wholesale Marketing Manager?

A. I started working for Avista in April 1990 as a Demand Side Resource Analyst. I joined the Energy Resources Department as a Power Contracts Analyst in June 1996. My primary responsibilities involve power contract origination and management and power supply regulatory issues.

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

A. My testimony will 1) identify and explain the proposed normalizing and pro forma adjustments to the January 2009 through December 2009 test period power supply

1 revenues and expenses, and 2) describe the proposed level
2 of authorized expense and retail revenue credit for the
3 Power Cost Adjustment (PCA) calculation purposes, using the
4 pro forma costs proposed by the Company in this filing.

5 **Q. Are you sponsoring any exhibits to be introduced**
6 **in this proceeding?**

7 A. Yes. I am sponsoring Exhibit No. 6, Schedules 1
8 through 4, which were prepared under my supervision and
9 direction.

10 **Q. Are other company witnesses providing testimony**
11 **regarding issues you are addressing?**

12 A. Yes. Company witness Mr. Kalich provides
13 detailed testimony on the AURORA model used by the Company
14 to develop short-term power purchase expense, fuel expense
15 and short-term power sales revenue included in my exhibits.

16

17 **II. OVERVIEW OF PRO FORMA POWER SUPPLY ADJUSTMENT**

18 **Q. Please provide an overview of the pro forma power**
19 **supply adjustment.**

20 A. The pro forma power supply adjustment involves
21 the determination of revenues and expenses based on the
22 generation and dispatch of Company resources and expected
23 wholesale market power prices as determined by the AURORA
24 model simulation for the pro forma period. In addition,
25 adjustments are made to reflect contract changes between

CASE NO. AVU-E-10-01

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UTILITIES COMMISSION
TO WILLIAM G. JOHNSON DIRECT TESTIMONY

(Marked)

1 the 2009 calendar-year test period and the pro forma period
 2 October 2010 to September 2011. The table below shows
 3 total net power supply expense during the test period and
 4 the pro forma period. For information purposes only, the
 5 power supply expense¹ currently in rates, which is based on
 6 a July 2009 through June 2010 pro forma period, is also
 7 shown.

Power Supply Expense (Not Including Directly Assigned Clearwater Paper Purchase)		
	<u>System</u>	<u>Idaho Allocation</u>
Power Supply Expense in Current Base Rates	\$169,037,000	
Actual Jan 09 - Dec 09 Power Supply Expense	\$189,811,000	
Adjustment to Test Period	\$29,376,000	\$10,319,789
Proposed Pro forma Power Supply Expense	\$219,187,000	
Increase from Expense in Current Rates	\$50,150,000	\$17,617,695

9 The net effect of my adjustments to the test year
 10 power supply expense is an increase of \$29,376,000
 11 (\$219,187,000 - \$189,811,000) on a system basis. The Idaho
 12 allocation of this adjustment of \$10,319,789 is
 13 incorporated into the revenue requirement calculation for
 14 the Idaho jurisdiction by Company witness Ms. Andrews.

15 The increase in power supply expense compared to the
 16 authorized level in current base rates is \$50,150,000
 17 (system) and \$17,617,695 (Idaho allocation).

¹ For the remainder of my testimony, for purposes of the power supply adjustment, I will refer to the net of power supply revenues and expenses as power supply expense for ease of reference.

1 Q. What are the major factors driving the increased
2 power supply expense in the pro forma year over the level
3 of power supply expense currently in base rates?

4 A. This increase in pro forma power supply expense
5 over the expense currently in base rates is based on
6 numerous factors, primarily the inclusion of expenses
7 related to the Lancaster Power Purchase Agreement (PPA),
8 the termination of four low cost power purchases, reduced
9 hydro generation and higher natural gas prices.

10 The Lancaster PPA increases power supply expense by
11 approximately \$21.3 million on a system basis or \$7.5
12 million for the Idaho allocation. The pro forma in this
13 case includes all expenses and revenues associated with the
14 Lancaster PPA. These include the Lancaster PPA charges,
15 gas transportation, transmission and fuel expense. These
16 expenses are partially offset by the value of the
17 generation. The fixed Lancaster PPA expenses, including
18 the PPA charges, gas transportation and transmission are
19 currently tracked in the Power Cost Adjustment (PCA) at
20 100%, while the variable costs and benefits, including
21 natural gas fuel and generation value are tracked in the
22 PCA at the normal 90/10 sharing between ratepayers and the
23 company.

24 Another big driver of increased expense in the pro
25 forma is the loss of four low cost 25 aMW power purchases

1 that end December 31, 2010. Those four purchases have an
2 average rate of \$31.68/MWh, well below their replacement
3 costs. The cost of replacement in the pro forma is
4 \$48.51/MWh. This leads to an increased expense of \$3.6
5 million (Idaho allocation).

6 Other expense increases are due to decreased hydro
7 generation, higher net wholesale contract costs and
8 increased fuel prices. Lower retail load reduces power
9 supply expense.

10 Hydro generation is lower by 43.4 aMW in the pro forma
11 versus the amount in the current base rates. The loss of
12 hydro generation is due to several factors. The first is a
13 reduction in generation from Avista's plants on the Clark
14 Fork River as explained in Mr. Kalich's testimony. The
15 second is a reduction in Mid-Columbia purchased hydro
16 generation. This is due to reduced allocation for Avista
17 of Grant County PUD's Priest Rapids Project, and the
18 expiration of Avista's purchase of the Colville Indian
19 Tribe's share of the Wells project on September 30, 2010.
20 The net impact of reduced hydro generation is an increased
21 expense of \$2.5 million (Idaho allocation).

22 Higher net wholesale contract costs increase power
23 supply expense by \$.7 million (Idaho allocation), and is
24 primarily a result of reduced wholesale revenues due to the

1 expiration of a load following contract with NorthWestern
2 Energy along with other contract volume and price changes.

3 Higher fuel prices increases power supply expense by
4 \$5.3 million (Idaho allocation). This impact is the sum of
5 higher natural gas fuel prices (\$4.1 million) and higher
6 net costs at Colstrip and Kettle Falls (\$1.2 million).
7 Natural gas prices in this pro forma are \$6.26/dth
8 (Stanfield) compared to \$4.79/dth in the current base
9 rates.

10 A reduction in retail loads reduces power supply
11 expense by \$2.1 million (Idaho allocation). Pro forma
12 system loads are 13.5 aMW lower than loads that current
13 rates are based on. Most of this increase is mitigated by
14 the production property adjustment so the net impact of
15 lower retail loads is small.

16 The table below shows the primary factors driving the
17 increase in power supply expense compared to the level in
18 current base rates.

**Power Supply Expense Change
Oct 10-Sep-11 Pro forma vs. Current Authorized**

<u>Factor</u>	<u>Pro Forma to Authorized Change \$millions</u>	<u>Idaho Allocation \$millions</u>
Lancaster	\$21.3	\$7.5
Decreased System Load	-\$6.0	-\$2.1
Low Cost 100 MW Purchase Ends	\$10.3	\$3.6
Reduced Hydro Generation	\$7.1	\$2.5
Colstrip and Kettle Falls Fuel	\$3.5	\$1.2
Purchase Contracts	\$2.1	\$0.7
Higher Natural Gas Prices	\$11.8	\$4.1
Total Power Supply Increase	\$50.1	\$17.6

III. PRO FORMA POWER SUPPLY EXPENSE ADJUSTMENTS

Overview

Q. Please identify the specific power supply cost items that are covered by your testimony and the total adjustment being proposed.

A. Exhibit No. 6, Schedule 1 identifies the power supply expense and revenue items that fall within the scope of my testimony. These revenue and expense items are related to power purchases and sales, fuel expenses, transmission expense, and other miscellaneous power supply expenses and revenues.

Q. What is the basis for the adjustments to the test period power supply revenues and expenses?

1 A. The purpose of the adjustments to the test period
2 is to normalize power supply expenses for normal weather
3 and normal hydroelectric generation and to reflect known
4 and measurable changes for the pro forma period that retail
5 rates will be in effect. Adjustments are also made to
6 reflect contract changes from the test period to the pro
7 forma period.

8 The AURORA Model, as explained by Mr. Kalich,
9 dispatches Company resources on an hourly basis and
10 calculates the level of generation from the Company's
11 thermal resources, fuel costs for thermal resources, and
12 the short-term purchases and sales necessary to serve
13 system requirements.

14 **Q. Have any changes been made in the calculation of**
15 **pro forma power supply costs from the last general rate**
16 **case?**

17 A. No. The process to develop the pro forma net
18 power supply expense in this case is the same as in the
19 2009 general rate case.

20 A brief description of each adjustment is provided in
21 Exhibit No. 6, Schedule 2. Detailed workpapers have been
22 provided to the Commission coincident to this filing to
23 support each of the pro forma revenues and expenses. The
24 detailed workpapers for each adjustment show the actual

1 revenue or expense in the test period, and the pro forma
2 revenue or expense.

3 **Long-Term Contracts**

4 **Q. How are long-term power contracts included in**
5 **the pro forma?**

6 A. Long-term power contracts are included in the pro
7 forma by including the energy receipt or obligation
8 associated with the contract in the AURORA model and
9 including the cost or revenue in the pro forma net power
10 supply expense.

11 **Q. Are there any new long-term power purchases or**
12 **sales in the pro forma?**

13 A. Yes. This pro forma includes the expenses and
14 revenues related to the Lancaster power purchase agreement.
15 These expenses and revenues are not in the authorized power
16 supply expense supporting current base rates and are being
17 tracked in the PCA.

18 **Q. Are there any power purchases or sales that are**
19 **in current base rates but not in this pro forma?**

20 A. Yes. As stated earlier, one of the larger
21 factors driving expenses higher is the expiration of four
22 low cost 25 aMW purchases at the end of 2010. Also as
23 discussed earlier, the company's purchase of the Colville
24 Indian Tribe's share of Wells dam ends September 30, 2010.

1 On the revenue side, the load following contract with
2 NorthWestern Energy ends January 9, 2011.

3 **Short-Term Power Purchases and Sales**

4 Q. How are short-term transactions included in the
5 pro forma?

6 A. Short-term electric power purchases and sales are
7 an output of the AURORA model. The model calculates both
8 the volumes and price of short-term purchases and sales
9 that balance the system's generation and long-term
10 purchases with retail load and other obligations. The
11 price of the short-term transactions represents the price
12 of spot market power as determined by the AURORA model.

13 **Thermal Fuel Expense**

14 Q. How are thermal fuel expenses determined in the
15 pro forma?

16 A. Thermal fuel expenses include Colstrip coal
17 costs, Kettle Falls wood waste costs and natural gas
18 expense for the Company's gas-fired resources consisting of
19 Coyote Springs 2, Lancaster PPA, Rathdrum, Northeast,
20 Boulder Park, and the Kettle Falls combustion turbine.
21 Unit coal costs at Colstrip are based on the long-term coal
22 supply and transportation agreements. Unit wood fuel costs
23 at Kettle Falls are based on multiple shorter-term
24 contracts with fuel suppliers and inventory. Total fuel
25 costs for each plant are based on the unit fuel cost and

1 the plant's level of generation as determined by the AURORA
2 model. Exhibit No. 6, Schedule 3 shows the pro forma fuel
3 costs by month for each plant. Mr. Kalich provides details
4 and supporting workpapers regarding the level of generation
5 for the Company's thermal plants, and the fuel costs for
6 the natural gas-fired and thermal plants.

7 **Transmission Expense**

8 Q. What changes in transmission expense are in the
9 pro forma compared to the test year or the current base
10 rates?

11 The pro forma in this case includes the purchase of
12 250 MW of BPA point-to-point transmission for the Lancaster
13 plant. The annual cost of this transmission is \$4.5
14 million (system basis).
15

16 **IV. PCA CALCULATIONS**

17 **Proposed Changes to the PCA**

18 Q. Is the Company proposing any changes to the PCA?

19 A. Yes. The Company is proposing to remove the
20 separate 100% tracking of Lancaster fixed expenses in the
21 PCA as all of Lancaster PPA's related expenses and revenues
22 will be included in the authorized power supply expense in
23 the PCA.
24
25

1 **New Authorized Power Supply and Transmission Expense**

2 Q. What is the authorized power supply expense and
3 revenue proposed by the Company for the PCA?

4 A. The proposed authorized level of annual system
5 power supply expense is \$200,570,792. This is the sum of
6 Accounts 555 (Purchased Power), 501 (Thermal Fuel), 547
7 (Fuel), less Account 447 (Sale for Resale). The proposed
8 level of Transmission Expense is \$17,648,340. The proposed
9 level of Transmission Revenue is \$12,388,460.

10 The level of retail sales and the retail revenue
11 credit will also be updated. The proposed authorized level
12 of retail sales to be used in the PCA is the October 2009
13 through September 2011 pro forma retail sales. The
14 proposed retail revenue credit is \$50.26/MWh, which is the
15 average cost of production/transmission in this filing.

16 The proposed authorized monthly PCA expense and
17 revenue is shown in Exhibit 6, Schedule 4.

18 Q. Does that conclude your pre-filed direct
19 testimony?

20 A. Yes.

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IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-10-01
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 6
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	WILLIAM G. JOHNSON

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

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Avista Corp.
Power Supply Pro forma - Idaho Jurisdiction
System Numbers - Jan 2009 - Dec 2009 Actual and Oct 2010 - Sep 2011 Pro Forma

IDAHO PUBLIC UTILITIES COMMISSION

Line No.	Jan 09 - Dec 09 Actuals	Adjustment	Oct 10 - Sep 11 Pro forma
<u>555 PURCHASED POWER</u>			
1	Modeled Short-Term Market Purchases	\$0	\$31,363
2	Actual ST Market Purchases - Physical	198,063	-198,063
3	Rocky Reach	1,658	439
4	Wanapum	4,989	-4,989
5	Wells - Avista Share	1,412	140
6	Wells - Colville Tribe's Share	11,202	-11,202
7	Priest Rapids Project	4,999	692
8	Grant Displacement	5,333	326
9	Douglas Settlement	365	219
10	Lancaster Capacity Payment	0	20,999
11	Lancaster Variable O&M Payments	0	2,555
12	Lancaster BPA Reserves	0	744
13	WNP-3	14,078	-1,825
14	Deer Lake-IP&L	7	0
15	Small Power	904	115
16	Stimson	1,865	300
17	Spokane-Upriver	1,792	211
18	Douglas Exchange Capacity	1,511	-1,511
19	Seattle Exchange Capacity	1,535	-1,535
20	Black Creek Index Purchase	139	-5
21	Non-Monetary	-142	142
22	Contract A	6,789	-5,077
23	Contract B	6,745	-5,044
24	Contract C	6,657	-4,978
25	Contract D	7,556	-5,651
26	Northwestern Deviation Energy	1,661	-1,661
27	BPA NT Deviation Energy	1,101	-1,101
28	Clearwater Paper Co-Gen Purchase	19,413	-19,413
29	Spinning Reserve Purchase	622	0
30	Ancillary Services	686	-686
31	Stateline Wind Purchase	2,846	685
32	Total Account 555	303,786	-203,811
<u>557 OTHER EXPENSES</u>			
33	Broker Commission Fees	124	0
34	REC Purchases	350	0
35	Natural Gas Fuel Purchases	32,480	-32,480
36	Total Account 557	32,954	-32,480
<u>501 THERMAL FUEL EXPENSE</u>			
37	Kettle Falls - Wood Fuel	7,450	2,830
38	Kettle Falls - Start-up Gas	47	0
39	Colstrip - Coal	13,336	7,012
40	Colstrip - Oil	113	85
41	Total Account 501	20,946	9,927
<u>547 OTHER FUEL EXPENSE</u>			
42	Coyote Springs Gas	57,429	-2,651
43	CS2 Gas Transportation Charge	6,832	1,052
44	Lancaster Gas	0	57,669
45	Lancaster Gas Transportation Charge	0	6,014
46	Lancaster Gas Transportation Optimization	0	-392
47	Rathdrum Gas	2,628	-2,285
48	Northeast CT Gas	3	73
49	Boulder Park Gas	1,461	-1,276
50	Kettle Falls CT Gas	303	-101
51	Total Account 547	68,656	58,102

Exhibit No. 6
Case No. AVU-E-10-01
W. Johnson, Avista
Schedule 1, p. 1 of 2

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Avista Corp.
Power Supply Pro forma - Idaho Jurisdiction
System Numbers - Jan 2009 - Dec 2009 Actual and Oct 2010 - Sep 2011 Pro Forma

Line No.	Jan 09 - Dec 09 Actuals	Adjustment	Oct 10 - Sep 11 Pro forma
<u>565 TRANSMISSION OF ELECTRICITY BY OTHERS</u>			
52 WNP-3	789	0	789
53 Sand Dunes-Warden	13	0	13
54 Black Creek Wheeling	25	-4	21
55 Wheeling for System Sales & Purchases	332	0	332
56 PTP Transmission for Colstrip & Coyote	8,432	-2	8,430
57 PTP Transmission for Lancaster	0	4,503	4,503
58 Redirected Lancaster Transmission	0	-241	-241
59 BPA Townsend-Garrison Wheeling	1,173	0	1,173
60 Avista on BPA - Borderline	1,530	0	1,530
61 Kootenai for Worley	45	0	45
62 Sagle-Northern Lights	140	0	140
63 Garrison-Burke	226	44	270
64 PGE Firm Wheeling	647	-4	643
65 Total Account 565	13,352	4,296	17,648
<u>536 WATER FOR POWER</u>			
66 Headwater Benefits Payments	716	7	723
<u>549 MISC OTHER GENERATION EXPENSE</u>			
67 Rathdrum Municipal Payment	160	0	160
68 TOTAL EXPENSE	440,570	-163,960	276,610
<u>447 SALES FOR RESALE</u>			
69 Modeled Short-Term Market Sales	0	45,214	45,214
70 Actual ST Market Sales - Physical	158,707	-158,707	0
71 Peaker (PGE) Capacity Sale	1,748	0	1,748
72 Nichols Pumping Sale	1,642	1,511	3,153
73 Sovereign/Kaiser DES	511	-432	79
74 Pend Oreille DES & Spinning	613	-154	459
75 Northwestern Load Following	4,554	-3,556	998
76 NaturEner	313	-313	0
77 SMUD Sale	27,648	-22,265	5,383
78 Ancillary Services	686	-686	0
79 BPA NT Deviation Energy	1,233	-1,233	0
80 Total Account 447	197,655	-140,621	57,034
<u>456 OTHER ELECTRIC REVENUE</u>			
81 Renewable Energy Credit Sales	144	-144	0
82 Gas Not Consumed Sales Revenue	33,137	-33,137	0
83 Total Account 456	33,281	-33,281	0
<u>453 SALES OF WATER AND WATER POWER</u>			
84 Upstream Storage Revenue	381	-20	361
<u>454 MISC RENTS</u>			
85 Colstrip Rents	29	0	29
86 TOTAL REVENUE	231,346	-173,922	57,424
87 TOTAL NET EXPENSE	209,224	9,963	219,187
88 Clearwater Paper Purchase Assigned to Idaho		19,413	
89 Total Adjustment Including Clearwater Paper		29,376	

Avista Corp.
Power Supply Pro forma - Idaho Jurisdiction
System Numbers - Jan 2009 - Dec 2009 Actual and Oct 2010 - Sep 2011 Pro Forma

Line No.		Jan 09 - Dec 09 Actuals	Adjustment	Oct 10 - Sep 11 Pro forma
70	Actual ST Market Sales - Physical	158,707	-158,707	0
71	Peaker (PGE) Capacity Sale	1,748	0	1,748
72	Nichols Pumping Sale	1,642	1,509	3,151
73	Sovereign/Kaiser DES	511	-432	79
74	Pend Oreille DES & Spinning	613	-154	459
75	Northwestern Load Following	4,554	-3,556	998
76	NaturEner	313	-313	0
77	SMUD Sale	27,648	-22,265	5,383
78	Ancillary Services	686	-686	0
79	BPA NT Deviation Energy	1,233	-1,233	0
80	Total Account 447	197,655	-138,945	58,710
	456 OTHER ELECTRIC REVENUE			
81	Renewable Energy Credit Sales	144	-144	0
82	Gas Not Consumed Sales Revenue	33,137	-33,137	0
83	Total Account 456	33,281	-33,281	0
	453 SALES OF WATER AND WATER POWER			
84	Upstream Storage Revenue	381	-20	361
	454 MISC RENTS			
85	Colstrip Rents	29	0	29
86	TOTAL REVENUE	231,346	-172,246	59,100
87	TOTAL NET EXPENSE	209,224	8,679	217,903
88	Clearwater Paper Purchase Assigned to Idaho		19,413	
89	Total Adjustment Including Clearwater Paper		28,092	

Avista Corp.
Brief Description of Power Supply Adjustments

Line No.

- 1 **Modeled Short-term Market Purchases** - Short-term purchases from the
2 AURORA Dispatch Simulation Model.
- 3
- 4 **Actual ST Market Purchases-Physical** - Expense of the actual term physical
5 power transactions in the test year.
- 6
- 7 **Rocky Reach** - The Pro forma cost for Rocky Reach is based on Chelan
8 PUD's budgeted expenses. Avista's costs are based on the Company's 2.9%
9 share of total cost. The contract terminates 10-31-11.
- 10
- 11 **Wanapum** - The Wanapum contract expires October 31, 2009. Beginning
12 November 2009 Wanapum becomes part of the Priest Rapids Project and
13 Wanapum costs are included in the Priest Rapids Project costs.
- 14
- 15 **Wells - Avista Share** - Wells' costs are based on the Company's 3.34% share
16 of total cost at project costs.
- 17
- 18 **Wells - Colville Tribe's Share** - The 2009 test year included 4.5% of Well's
19 output purchased from the Colville Indian Tribe that terminates 9-30-10.
- 20
- 21
- 22 **Priest Rapids Project** - Priest Rapids Project expense includes the expense
23 related to the purchased power from the Priest Rapids development and power
24 from the Wanapum development.
- 25
- 26 **Grant Displacement** - Grant Displacement is scheduled energy from Grant
27 PUD that is priced at Grant's cost. This contract ends 9-30-11.
- 28
- 29 **Douglas Settlement** - Douglas Settlement is for power Avista purchases from
30 Douglas PUD per the 1989 Settlement Agreement.
- 31
- 32 **Lancaster Capacity Payment** - The Lancaster capacity payment includes a
33 capital payment and a fixed O&M payment.
- 34
- 35
- 36
- 37

- 1 11 **Lancaster Variable Energy Payment** - The Lancaster variable energy
2 payment is based on the variable energy rate in the Lancaster Power Purchase
3 Agreement multiplied time the MWh of Lancaster generation in the pro forma.
4
- 5 12 **Lancaster BPA Reserves** - Because Lancaster is in BPA's balancing
6 authority, Avista purchases reserves for the plant from BPA. The expense is
7 based on BPA's reserve rate times 7% of Lancaster generation in the pro
8 forma.
9
- 10 13 **WNP-3** - Pro forma costs are based on the lower of actual costs or the
11 midpoint. The pro forma uses the actual rate for contract year 2009 through
12 2010 escalated at the 5-year average escalation rate to the pro forma period.
13
- 14 14 **Deer Lake-IP&L** - Pro forma expense is for power purchased from Inland
15 Power to serve Avista customers.
16
- 17 15 **Small Power - Pro forma** costs are based on 5-year average generation and an
18 average contract rate.
19
- 20 16 **Stimson** - This purchase is from the cogeneration plant at Plummer, Idaho.
21 Pro forma costs are based on 5-year average generation and pro forma period
22 contract rates.
23
- 24 17 **Spokane-Upriver** - Pro forma expense is based on a purchase on the net of
25 pumping (at the plant) generation at the contract rate.
26
- 27 18 **Douglas Exchange Capacity** - Pro forma is \$0 because Avista bids annually
28 for this capacity.
29
- 30 19 **Seattle Exchange Capacity** - Pro forma is \$0 because contract terminates 9-
31 30-10.
32
- 33 20 **Black Creek Index Purchase** - Expense is for an October purchase at index
34 prices less transmission expense and a margin.
35
- 36 21 **Non-Monetary** - Expense is normalized to \$0 in the Pro forma.
37
- 38 22 **Contract A** - Pro forma expense is for a 2007 through 2010 25 MW power
39 purchase. (Contract details are provided in a CONFIDENTIAL workpaper).
40

- 1 23 **Contract B** - Pro forma expense is for a 2007 through 2010 25 MW power
2 purchase. (Contract details are provided in a CONFIDENTIAL workpaper).
3
4 24 **Contract C** - Pro forma expense is for a 2007 through 2010 25 MW power
5 purchase. (Contract details are provided in a CONFIDENTIAL workpaper).
6
7 25 **Contract D** - Pro forma expense is for a 2007 through 2010 25 MW power
8 purchase. (Contract details are provided in a CONFIDENTIAL workpaper).
9
10 26 **NorthWestern Load Following Deviation Energy** - Pro forma expense is \$0
11 because deviation energy is priced at market and is not included In AURORA
12 model.
13
14 27 **BPA NT Deviation Energy** - Pro forma expense is \$0 because deviation
15 energy is priced at market and is not included In AURORA model.
16
17 28 **Clearwater Paper Co-Gen Purchase** - Pro forma expense is \$0 because
18 Clearwater Paper purchase expense is directly assigned to the Idaho
19 jurisdiction and is not included in system power supply expense.
20
21 29 **Spinning Reserve Purchase** - Pro forma expense is for a purchase of spinning
22 reserves during the months of May through July that matches the test year
23 purchase expense. The AURORA model does not include reserves.
24
25 30 **Ancillary Services** - Pro forma expense is \$0 because this is an intra-utility
26 expense (matching revenue in Account 447).
27
28 31 **Stateline Wind Purchase** - Pro forma expense is for a 10-year purchase from
29 a Northwest wind project. Expense is based on expected energy amount times
30 the contract rate. (Contract details are provided in a CONFIDENTIAL
31 workpaper).
32
33 32 **Total Account 555**
34
35 33 **Broker Commission Fees** - Pro forma expense is associated with purchases
36 and sales of electricity and natural gas fuel.
37
38 34 **REC Purchases** - Expense is for the purchase of California certifiable
39 renewable Energy Credits to support the SMUD Sale.
40

- 1 35 **Natural Gas Fuel Purchases** - This is the expense for natural gas purchased
2 for but not consumed for generation. Pro forma expense is \$0 because all gas
3 purchased is assumed to be used for generation, and included in Account 547.
4
- 5 36 **Total Account 557**
6
- 7 37 **Kettle Falls Wood Fuel Cost** - Pro forma fuel expense is based on the
8 generation of the Kettle Falls plant in the AURORA Model and the projected
9 unit cost of fuel.
10
- 11 38 **Kettle Falls-Start-up Gas** - Pro forma expense is for start-up gas at Kettle
12 Falls and is based on the test-year expense.
13
- 14 39 **Colstrip Coal Cost** - Pro forma fuel expense is based on the generation of the
15 Colstrip plant in the AURORA Model and the projected unit cost of fuel.
16
- 17 40 **Colstrip Oil** - Pro forma expense is for start-up oil expense. Pro forma is
18 based on a five year average.
19
- 20 41 **Total Account 501**
21
- 22 42 **Coyote Springs Gas** - Pro forma expense is an output of the AURORA Model
23 based on the projected unit cost of fuel and the dispatch of the plant, which
24 determines the volume of fuel consumed.
25
- 26 43 **CS2 Gas Transportation** - This expense is for transportation of natural gas to
27 the Coyote Springs 2 plant.
28
- 29 44 **Lancaster Gas** - Pro forma expense is an output of the AURORA Model
30 based on the projected unit cost of fuel and the dispatch of the plant, which
31 determines the volume of fuel consumed.
32
- 33 45 **Lancaster Gas Transportation** - This expense is for natural gas
34 transportation to the Lancaster plant.
35
- 36 46 **Lancaster Gas Transportation Optimization** - This credit to expense is
37 based on optimizing the gas transportation contracts for Coyote Springs 2 and
38 Lancaster. In general, this involves trading the gas price spread between
39 AECO (Canada) and Malin.
40
41

- 1 47 **Rathdrum Gas** - Pro forma expense is an output of the AURORA Model
2 based on the projected unit cost of fuel and the dispatch of the plant, which
3 determines the volume of fuel consumed.
4
- 5 48 **Northeast CT Gas** - Pro forma expense is an output of the AURORA Model
6 based on the projected unit cost of fuel and the dispatch of the plant, which
7 determines the volume of fuel consumed.
8
- 9 49 **Boulder Park Gas** - Pro forma expense is an output of the AURORA Model
10 based on the projected unit cost of fuel and the dispatch of the plant, which
11 determines the volume of fuel consumed.
12
- 13 50 **Kettle Falls CT Gas** - Pro forma expense is an output of the AURORA Model
14 based on the projected unit cost of fuel and the dispatch of the plant, which
15 determines the volume of fuel consumed.
16
- 17 51 **Total Account 547**
18
- 19 52 **WNP-3 Transmission** - Pro forma WNP-3 transmission is based on 32.22
20 MW at a rate of \$2.04/kW/mo.
21
- 22 53 **Sand Dunes-Warden** - Pro forma expense is for a transmission expense with
23 Grant PUD.
24
- 25 54 **Black Creek Wheeling** - Expense is for wheeling and shaping associated with
26 the Black Creek power purchase. The purchase rate is reduced by the
27 wheeling expense.
28
- 29 55 **Wheeling for System Sales and Purchases** - Pro forma expense is for short-
30 term transmission purchases.
31
- 32 56 **PTP for Colstrip and Coyotes Springs 2** - This wheeling is for the
33 transmission of 196 MW from Colstrip at the Garrison substation and 272
34 MW from the Coyote Springs 2 plant to Avista's system. Pro forma expense
35 is based on 468 MW of capacity at a rate of \$1.501/kW/mo.
36
- 37 57 **PTP for Lancaster** - This wheeling is for the transmission from the Lancaster
38 plant to Avista's system. Pro forma expense is based on 250 MW of capacity
39 at a rate of \$1.501/kW/mo.
40

- 1 58 **Redirected Lancaster Transmission** - This credit is for the Lancaster
2 transmission that is redirected and used when the plant is off-line or not
3 operating at full capacity.
4
- 5 59 **BPA Townsend-Garrison Wheeling** - This expense is for the transmission
6 of Colstrip power from the Townsend substation to the Garrison substation.
7
- 8 60 **Avista on BPA Borderline** - This expense is to serve Avista load off of BPA
9 transmission. The expense is based on Avista's borderline loads priced at
10 BPA's NT transmission rates plus ancillary services cost and use of facilities
11 charges.
12
- 13 61 **Kootenai for Worley** - This expense is for Avista load served using Kootenai
14 PUD's facilities.
15
- 16 62 **Sagle-Northern Lights** - Expense is for transmission purchased from
17 Northern Lights Utility to serve Avista customers.
18
- 19 63 **Garrison Burke** - Garrison Burke wheeling is an expense for the transmission
20 of Colstrip energy above 196 MW from the Garrison substation over
21 Northwestern Energy's transmission system to the interconnection of
22 Northwestern Energy and Avista. Expense is based on a 5-year average.
23
- 24 64 **PGE Firm Wheeling** - PGE Firm wheeling reflects the cost of transmission
25 from the John Day substation to COB (Intertie South) purchased from Portland
26 General Electric. The Pro forma expense is based on 100 MW at the current
27 rate of \$.53549/kW/mo.
28
- 29 65 **Total Account 565**
30
- 31 66 **Headwater Benefits Expense** - Pro forma expense is based on the expense for
32 contract year September 2009 through August 2010.
33
- 34 67 **Rathdrum Municipal Payment** - This includes a payment in Jan. 2011 of
35 \$160,000 to the city of Rathdrum for mitigation related to the Rathdrum
36 generating facility.
37
- 38 68 **Total Expenses** - Sum of Accounts 555, 557, 501, 547, 565, 536, and 549.
39
- 40 69 **Modeled Short-Term Market Sales** - Short-term market sales from the
41 AURORA Model simulation.

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- 70 **Actual ST Market Sales-Physical** - Revenue from the actual term transactions in the test year.
- 71 **Peaker (PGE) Capacity Sale** - This Pro forma revenue is based on 150 MW of capacity at a price of \$1/kW/mo less a contract servicing fee.
- 72 **Nichols Pumping Sale** - This is a sale of energy to other Colstrip Units 3 and 4 owners at the Mid Columbia index price less \$2.05/MWh. Pro forma revenue is based on approximately 8 MW at the market price (less \$2.05/MWh) as determined by the AURORA model.
- 73 **Sovereign/Kaiser DES** - This contract provides load control services to Kaiser's Trentwood plant. (Contract details are provided in a CONFIDENTIAL workpaper).
- 74 **Pend Oreille DES & Spinning Reserves** - This contract provides load control and spinning reserves for Pend Oreille PUD. (Contract details are provided in a CONFIDENTIAL workpaper).
- 75 **Northwestern Load Following** - This contract provides load following capacity to NorthWestern Energy. Contract ends 1-9-11. (Contract details are provided in a CONFIDENTIAL workpaper).
- 76 **NaturEner** - This contract provides load following capacity to a Montana wind facility. Contract ends 6-30-10.
- 77 **SMUD Sale** - Pro forma revenue is the expected margin (margin only, not including index priced energy) from the sale of energy and associated renewable energy credits.
- 78 **Ancillary Services** - Pro forma revenue is \$0 because it is intra-utility revenue (matching expense in Account 555).
- 79 **BPA NT Deviation Energy** - Pro forma revenue is \$0 because deviation energy is priced at index and is not included in the AURORA model.
- 80 **Total Account 447**
- 81 **Renewable Energy Credit Sales** - Pro forma revenue is \$0 because test year revenue was for non-reoccurring renewable energy credit sales.

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- 82 **Gas Not Consumed Sales Revenue** - This is the revenue for natural gas purchased for but not consumed for generation. Pro forma expense is \$0 because all gas purchased is assumed to be used for generation, and included in Account 547.
- 83 **Total Account 456**
- 84 **Upstream Storage Revenue** - Pro forma revenue is based on the revenue for contract year September 2009 through August 2010.
- 85 **Colstrip Rents** - Pro forma revenue is based on expected revenue.
- 86 **Total Revenue** – Sum of Accounts 447, 456, 453 and 454.
- 87 **Total Net Expense** – Total expense minus total revenue.
- 88 **Clearwater Paper Purchase Assigned to Idaho** - This line shows the Clearwater Paper purchase adjustment. The Clearwater Paper expense is directly assigned to Idaho and is not included in the pro forma system power supply expense. The Clearwater Paper purchase expense is included in the adjustment in line 89 to show the total adjustment from test year actual expense (includes Clearwater Paper) to the Pro forma.
- 89 **Total Adjustment Including Clearwater Paper** - This is the total adjustment in power supply expense factoring in the Clearwater Paper purchase expense directly assigned to Idaho.

**Avista Corp.
Market Purchases and Sales, Plant Generation and Fuel Cost Summary
Idaho Proforma October 2010 - September 2011**

	744	672	743	709	744	744	720	744	744	720	744	Nov-10	721	744
	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-10	Nov-10	Dec-10		
Total														
Market Sales - Dollars	\$-1,708,632	\$-1,708,358	\$-2,372,510	\$-2,743,082	\$-3,574,984	\$-3,732,836	\$-5,372,409	\$-2,882,435	\$-2,820,575	\$-3,130,375	\$-4,919,886	\$-9,158,954		
Market Sales - MWh	(30,077)	(50,062)	-48,462	-76,903	-137,772	-148,109	-111,866	-56,782	-59,389	-71,425	-102,001	-160,613		
Average Market Sales Price - \$/MWh	\$56.81	\$54.14	\$48.96	\$36.97	\$25.95	\$25.07	\$48.03	\$50.76	\$48.46	\$43.83	\$48.23	\$57.01		
Market Purchases - Dollars	\$5,074,814	\$3,347,531	\$5,022,933	\$2,385,237	\$1,324,753	\$1,390,446	\$2,320,446	\$4,257,903	\$2,854,514	\$2,019,367	\$1,109,436	\$451,488		
Market Purchases - MWh	90,962	57,233	95,321	53,022	32,580	34,197	30,735	37,939	46,863	41,647	20,039	7,954		
Average Market Purchase Price - \$/MWh	\$55.78	\$58.49	\$52.70	\$44.98	\$40.68	\$40.68	\$53.48	\$62.76	\$61.17	\$48.48	\$55.37	\$56.77		
Net Market Purchases (Sales) MWh	60,885	7,171	48,859	-23,881	-105,192	-113,912	-72,131	11,057	-11,708	-29,778	-81,972	-152,660		
Net Market Purchases (Sales) MW	82	11	63	-33	-141	-158	-97	15	-40	-16	-14	-205		
Average Sale and Purchase Price - \$/MWh	\$56.04	\$56.46	\$51.43	\$40.24	\$38.76	\$27.99	\$48.46	\$57.30	\$54.11	\$45.54	\$49.41	\$57.00		
Colestrip MWH	147,656	135,220	146,716	129,388	104,967	97,758	142,181	149,834	144,878	148,496	144,879	147,298		
Colestrip Fuel Cost \$/MWh	\$12.41	\$12.68	\$12.64	\$12.82	\$13.23	\$13.27	\$12.72	\$12.64	\$11.43	\$11.43	\$11.42	\$11.44		
Colestrip Fuel Cost	\$1,869,131	\$1,708,979	\$1,858,654	\$1,659,011	\$1,388,227	\$1,297,356	\$1,808,202	\$1,891,254	\$1,831,040	\$1,896,985	\$1,654,016	\$1,684,970		
Kettle Falls MWH	294,847	33,085	33,887	#DIV/0!	0	0	27,776	33,888	32,009	34,416	33,305	34,411		
Kettle Falls Fuel Cost \$/MWh	\$35.45	\$35.44	\$35.44	#DIV/0!	0	0	\$95.87	\$57.45	\$35.45	\$33.74	\$33.74	\$33.74		
Kettle Falls Fuel Cost	\$1,207,849	\$1,101,680	\$1,201,137				\$2,697,912	\$1,201,309	\$1,134,647	\$1,161,026	\$1,123,574	\$1,160,995		
Coyote Springs MWH	129,533	126,369	101,223	32,206	17,202	30,345	122,112	154,805	150,022	122,493	139,921	148,972		
Coyote Springs Fuel Cost \$/MWh	\$44.38	\$45.91	\$44.96	\$41.70	\$41.70	\$42.42	\$41.95	\$41.36	\$41.78	\$39.20	\$41.96	\$44.43		
Coyote Springs Fuel Cost	\$6,005,019	\$5,801,319	\$4,550,956	\$1,337,710	\$717,287	\$1,287,142	\$5,122,948	\$6,395,211	\$6,267,859	\$4,801,647	\$5,871,626	\$6,618,903		
Lancaster MWH	133,225	127,403	102,880	29,907	17,548	19,425	110,082	152,557	149,154	117,577	152,480	154,398		
Lancaster Fuel Cost \$/MWh	\$48.04	\$47.72	\$46.75	\$43.65	\$45.22	\$46.71	\$45.71	\$44.91	\$44.84	\$41.46	\$41.46	\$46.60		
Lancaster Fuel Cost	\$6,400,139	\$6,076,308	\$4,800,725	\$1,305,356	\$793,448	\$907,367	\$5,032,234	\$6,850,808	\$6,687,680	\$4,875,149	\$6,733,921	\$7,194,283		
Boulder Park MWH	237	101	40	9	42	104	1,635	897	49	0	7	1		
Boulder Park Fuel Cost \$/MWh	\$65.38	\$64.58	\$62.61	\$57.36	\$56.57	\$58.41	\$58.01	\$59.33	\$58.71	\$58.88	\$58.88	\$62.73		
Boulder Park Fuel Cost	\$15,470	\$6,504	\$2,468	\$504	\$2,362	\$5,867	\$94,842	\$53,243	\$2,775	\$0	\$447	\$40		</

Net Fuel and Purchase Expense

Exhibit No. 6
Case No. AVU-E-10-01
W. Johnson, Avista
Schedule 3, p. 1 of 1

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Avista Corp
Pro forma October 2010 - September 2011
PCA Authorized Expense and Retail Sales

PCA Authorized Power Supply Expense

	Total	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-10	Nov-10	Dec-10
Account 555 - Purchased Power	\$99,973,476	\$11,958,638	\$9,648,897	\$10,369,141	\$7,674,915	\$5,715,996	\$5,803,342	\$6,304,182	\$8,147,437	\$6,632,169	\$8,287,612	\$9,889,639	\$9,541,506
Account 501 - Thermal Fuel	\$30,872,641	\$3,097,364	\$2,831,043	\$3,080,375	\$1,679,395	\$1,408,611	\$1,317,720	\$2,816,497	\$3,112,947	\$2,986,072	\$2,878,395	\$2,797,974	\$2,866,249
Account 547 - Natural Gas Fuel	\$126,757,248	\$13,546,803	\$12,999,479	\$10,452,412	\$3,804,091	\$2,673,625	\$3,364,467	\$11,703,289	\$14,698,131	\$14,128,211	\$10,802,604	\$13,689,033	\$14,895,103
Account 447 - Sale for Resale	\$57,032,573	\$2,669,417	\$3,467,055	\$3,243,324	\$3,910,764	\$4,624,204	\$4,731,723	\$6,260,937	\$3,880,607	\$3,715,656	\$4,194,226	\$6,070,898	\$10,263,761
Power Supply Expense	\$200,570,792	\$25,933,388	\$22,012,364	\$20,658,604	\$9,247,636	\$5,174,028	\$5,753,806	\$14,563,031	\$22,077,908	\$20,030,797	\$17,774,384	\$20,305,748	\$17,039,097
Transmission Expense	\$17,648,340	\$1,469,612	\$1,469,612	\$1,469,612	\$1,469,612	\$1,469,612	\$1,469,612	\$1,469,612	\$1,482,612	\$1,469,612	\$1,469,612	\$1,469,612	\$1,469,612
Transmission Revenue	\$12,388,460	\$901,304	\$825,004	\$1,002,240	\$898,431	\$1,029,104	\$1,371,347	\$1,379,878	\$1,150,203	\$1,025,629	\$1,041,304	\$939,334	\$824,682

PCA Authorized Idaho Retail Sales

	Total	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-10	Nov-10	Dec-10
Total Retail Sales, MWh	3,520,611	344,110	305,499	306,081	271,677	271,340	270,297	287,198	287,002	265,380	283,088	300,962	327,976
Retail Revenue Credit Rate	\$50.26 /MWh												

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