Exhibit No.__(WGJ-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-06___________

DIRECT TESTIMONY OF

WILLIAM G. JOHNSON

REPRESENTING AVISTA CORPORATION

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 Senior Power Supply Analyst 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 Senior Power Supply Analyst?

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 wholesale power marketing and regulatory issues.

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

A. My testimony will describe the adjustments to the level of power supply revenues and expenses from the amount currently in base rates, and I will also describe the new base level of power supply costs for Energy Recovery Mechanism (ERM) calculation purposes, using the pro forma costs proposed by the Company in this filing.

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

A. Yes. I am sponsoring Exhibit Nos. ___ (WGJ-2) (Power Supply Pro Forma); ___ (WGJ-3) (Description of Power Supply Adjustments); ___ (WGJ-4) (Market Purchases and Sales, Plant Generation and Fuel Cost Summary); and ___ (WGJ-5) (Energy Recovery Mechanism proposed calculations), which were prepared under my supervision and direction.

Q. Are other Company witnesses providing testimony regarding issues you are addressing?

A. Yes. Company witness Mr. 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 included in my exhibits. Company witness Ms. Andrews sponsors the "Pro Forma Power Supply" adjustment for the Washington jurisdiction determined from my net system power supply adjustments.

II SUMMARY

Q. Please provide an overview of your direct testimony.

A. My testimony explains adjustments made to normalize power supply expense and revenue items in the pro forma period compared to the power supply expenses currently in base rates. This involves the determination of revenues and expenses based on normal stream flow and expected wholesale market power prices. In addition, adjustments are made to reflect contract changes in the 2007 pro forma period. The net effect of my adjustments to the power supply net expense currently in base rates is an increase of $51,132,000 on a system basis. The Washington allocation of this adjustment of $33,318,000 (before the

Retail Revenue Credit) is incorporated into the revenue requirement calculation for the Washington jurisdiction by Ms. Andrews.

III PRO FORMA POWER SUPPLY COSTS

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.___ (WGJ-2) 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 expense, transmission expense, and other miscellaneous power supply expenses and revenues.

Q. What is the basis for the adjustments to the power supply revenues and expenses currently in base rates?

A. Power supply expenses currently in base rates are based on a 2006 pro forma prepared for the Company's 2005 General Rate Case which used 2004 weather-adjusted loads. Power supply expenses in this case are based on a 2007 pro forma period using forecasted 2007 pro forma loads. Adjustments are also made to reflect contract changes effective in 2007.

As in past rate cases, power supply expenses are based on normal weather and normal stream flows. The AURORA model is used to normalize power supply revenues and expenses that are dependent upon hydroelectric generation and wholesale market electricity prices. The AURORA model dispatches Company resources on an hourly basis and calculates the level of generation from the Company's thermal resources along with the short-term purchases and sales necessary to serve system requirements.

Q. What changes has the Company made in the calculation of normal power supply costs from the 2005 General Rate Case?

A. The primary change is the use of loads that match the pro forma period. In this case, the pro forma period is calendar year 2007. In the prior case, the Company calculated pro forma power supply revenues and expenses to be included in base rates based on a 2006 pro forma period and historical 2004 test year loads. In this case the Company is using 2007 pro forma loads to better match revenues and expenses in the 2007 pro forma period.

Other than using pro forma loads, the process to develop the pro forma net power supply expense is the same as in past rate cases. Power supply adjustments have been prepared using the same methods that have been used in prior general rate cases.

A brief description of each adjustment is provided in Exhibit No. _____ (WGJ-3). Detailed workpapers have been provided coincident with this filing to support each of the pro forma revenues and expenses. The detailed workpapers for each adjustment show the level of revenue or expense currently in base retail rates, the actual revenue or expense in 2005, and the pro forma revenue or expense for 2007.

Q. What is the overall change in normalized power supply costs?

A. Power supply expense has increased by approximately $33.3 million (Washington allocation) from the level currently in base rates. This increase is primarily driven by wholesale electric and natural gas costs to serve increasing load requirements. Pro forma 2007 system loads are 72 aMW higher than the 2004 loads that current power supply expenses are based on. The increased power supply expense to meet this load is approximately $26.2 million (Washington allocation). The remaining increase in power supply expenses are primarily driven by increased fuel expense. Fuel expense is $25 million (Washington allocation) higher than the level currently in base rates. Some of the higher fuel expense is embedded in the cost of meeting load growth through the higher cost of market purchases that is driven by increased fuel prices. Offsetting some of the additional expense is an increase in wholesale sales revenue and the elimination of the Rathdrum lease expense because of the purchase of the plant.

Q. Is there a revenue offset to these increased power supply costs to serve retail loads?

A. Yes. As Ms. Andrews explains in her testimony, the power supply costs associated with the increased retail load is partially offset by additional revenue from increased retail sales. The offset (Retail Revenue Credit) is approximately $13.6 million of the $26.2 million increase in power supply costs associated with increased load requirements.

Q. Why is it important to use 2007 loads instead of 2005 loads when the ERM accounts for load changes and tracks the increased cost of meeting higher load requirements?

A. Because the marginal cost of power has become so much higher than the embedded cost, it is important to use loads that are matched with the pro forma period.

Consider a simple example. If actual loads are 1 MWh higher than the authorized level, the ERM will credit back $39.03 through the Retail Revenue Credit against the higher power supply expense. This is because the Company collects $39.03 from customers, as that is the average production and transmission cost included in the retail rate. If the cost of securing that extra MWh were $39.03, then there would be no impact in the ERM. The increased expense of serving another MWh of load would be exactly offset by the revenue collected from the customer and credited back through the ERM.

Current circumstances are very different than this example. Instead of $39.03 to secure an additional MWh, the cost is around $63. This means that an additional MWh of load creates increased power supply expense of $23.97 ($63 marginal cost of power minus the Retail Revenue Credit of $39.03). If this expense is multiplied by the 40 aMW difference between 2005 and 2007 loads, then annual power supply expense, all other costs being equal, will be understated by $5.5 million ($23.97 x 40 aMW x 8760 hrs/yr x 65.16% Washington allocation).

If the Company used 2005 historical loads instead of 2007 loads in developing the pro forma, then power supply expense would be understated by approximately $5.5 million and the Company would be disadvantaged because the deadband structure of the ERM would require the Company to absorb $4.8 million of that increased expense. This is not a result of the deadband itself, but rather a result of base power supply expenses not being set at the level of costs that are expected during the 2007 rate period. And while it is true that actual loads in 2007 will not be exactly at the forecasted level, there is a much higher chance that they will be closer to the forecasted level than they will be at the historical level two years earlier.

Long-Term Contracts

Q. How are long-term purchase contracts included in the pro forma?

A. Long-term purchase contracts are included in the pro forma by including the energy the contract provides in the AURORA model and including the cost based on the contract rates during 2007, multiplied by the energy volume.

Q. Are there any new power purchases in this pro forma that are not in the power supply expense included in current retail rates?

A. Yes, there are seven new long-term contracts that were not included in the pro forma in the last general rate case. Four of these new contracts are 25 MW purchases that replaced four 25 MW purchases that ended in 2006.

Q. Are any of these new contracts subject to the limitation for inclusion in the ERM that was part of the recent ERM Settlement?

A. No. The recent ERM Settlement included limitations on cost recovery for new or renewed contracts that are greater than 50 MW and have more than a two-year term. None of the new contracts included in this pro forma meet that criteria. Only one contract exceeds 50 MW, but that contract is not longer than two years and is an exchange contract that is used to provide transmission. The other new contracts are all less than 50 MW. All of the contracts were entered into prior to the ERM Settlement.

Any new agreements that are greater than 50 MW and more than two years in length will be addressed in a general rate case. The Company will continue to provide copies of all new contracts as part of its monthly ERM Deferral reports.

Q. How are power sale contracts included in the pro forma?

A. Power sale contracts are included in the pro forma in the same way as power purchases. The obligation of the power sale is included in the AURORA model and revenue from the sale is included in the pro forma based on the 2007 contract rate and the sale volume. Most of the Company's sale contracts are for load regulation capacity and do not include the sale of energy. For these contracts, the pro forma includes the revenue based on the contracted capacity and the 2007 contract rate. The obligation is included in AURORA through an on-peak obligation coupled with an equal energy off-peak resource.

Q. Are there any new sale contracts in this pro forma?

A. Yes. A load following capacity sale to Northwestern Energy is the only new sale contract in this pro forma that is not currently in base rates. This contract provides Northwestern Energy dynamic capacity from Avista's system to balance the instantaneous differences between resources and load. A copy of the contract was provided with the November 2005 ERM Monthly Deferral Report.

<u>Thermal Fuel Expense</u>

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

A. Thermal fuel expenses include Colstrip coal costs, Kettle Falls wood-waste costs and natural gas expense for the Company's gas-fired resources, which include Coyote Springs 2, Rathdrum, Northeast, Boulder Park, and the Kettle Falls combustion turbine. Unit coal costs at Colstrip are based on the long-term coal supply and transportation agreements. Unit wood-fuel costs at Kettle Falls are based on multiple shorter-term contracts with fuel suppliers and inventory. Unit fuel costs for natural gas are based on a three-month average of

2007 forward market prices consistent with the method approved in the Company's last rate case. Total fuel costs for each plant are based on the unit fuel cost and the plant's level of generation as determined by the AURORA model. Exhibit No. ____ (WGJ-4) shows the pro forma fuel costs by month for each plant.

Transmission Expense

Q. What are the differences in transmission expense in the 2007 pro forma in this case from the expense currently in base rates?

A. Transmission expense is similar in the 2007 pro forma to the level currently in base rates. The difference represents the amount of transmission expense included in the pro forma for CS2 and the two new transmission contracts that are not currently in base rates.

Q. What is the difference in the transmission purchased for CS2?

A. The Company currently purchases 222 MW of firm point-to-point (PTP) transmission from BPA and has an exchange agreement in place to meet the remaining transmission requirements for CS2. The prior case included 270 MW of firm PTP transmission, but did not include the exchange agreement. The exchange agreement, although used to provide transmission, is a purchase power expense in Account 555. The net effect is a reduction in Account 565 Transmission expense for CS2 and an increase in Account 555 Purchase Power expense.

Q. Are there any new transmission contracts that were not included in the prior General Rate Case?

A. Yes, there are two transmission purchases that were not included in the prior general rate case. The first, labeled Grant Transmission, is an agreement that began in 2006 and runs until November 2007 and has offsetting transmission revenues. The second new transmission expense is labeled Sagle-Northern Lights and is for the purchase of transmission from Northern Lights Utility to serve Avista customers in northern Idaho.

Q. How do the transmission adjustments you sponsor relate to the testimony of Mr. Kinney, the Company's transmission expert witness?

A. My transmission adjustments represent transmission expenses related to moving generation to and from our generation resources and our system. Mr. Kinney sponsors testimony involving issues associated with transmission planning and transmission revenues (transmission revenues are included in the ERM and noted in my testimony). I note this because the FERC Standards of Conduct rule prohibits my access, as a power supply employee, to certain transmission planning and revenue information.

Other Changes in Pro Forma

Q. Are there any other changes in power supply expense from what is currently in base retail rates?

A. Yes. This pro forma removes the Rathdrum lease expense. As explained by Company witness Mr. Peterson in his testimony, the Company determined that it was cost-effective to terminate the lease and purchase the plant. Ms. Andrews, in her testimony, explains how the Rathdrum plant is now included as part of the Company's rate base and how the associated costs are included in revenue requirements. The lease payment has been removed from power supply expense.

IV ERM CALCULATIONS

Q. What effect will this case have on the ERM?

A. The only effect this case will have on the ERM is to update the authorized expenses and revenues and the Retail Revenue Credit. ERM entries will continue to be calculated in the same manner as current calculations. The final order in this case will determine the new authorized level of power supply expenses, transmission expenses and revenues, and Retail Revenue Credit and retail load used in the ERM calculations.

Q. What are the new base numbers proposed by the Company for the ERM?

A. The proposed authorized level of annual power supply and transmission expense is $175,509,404. This is the sum of Accounts 555 (Purchased Power), 501 (Thermal Fuel), 547 (Fuel), 565 (Transmission) and broker fees, less Account 447 (Sales for Resale). The proposed level of transmission revenue (Account 456.100) is $9,892,740. (Transmission revenue numbers are provided by Mr. Kinney.)

The level of retail sales and the Retail Revenue Credit have also been updated. The proposed Retail Revenue Credit is $44.27/MWh. The proposed monthly power supply expense, transmission expense and revenue, and retail sales for ERM calculation purposes is shown in Exhibit No. ____(WGJ-5).

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

A. Yes.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-06________

EXHIBIT NO._____(WGJ-2)

WILLIAM G. JOHNSON

REPRESENTING AVISTA CORPORATION

Avista Corp.
Power Supply Pro Forma - Washington Jurisdiction
System Numbers - Authorized and 2007 Pro Forma

Line No.		Jan 06 - Dec 06 Authorized	Adjustment	Jan 07 - Dec 07 Normalized
	555 PURCHASED POWER			
1	Short-Term Market Purchases	$20,917	$15,946	$36,864
2	Rocky Reach	1,916	276	2,192
3	Wanapum	3,534	1,220	4,754
4	Wells	1,177	156	1,333
5	Priest Rapids Products	0	2,463	2,463
6	Grant Displacement	5,512	718	6,230
7	Grant Revenue Credit	-2,690	2,690	0
8	Douglas Settlement	0	717	717
9	WNP-3	13,906	-2,278	11,628
10	Deer Lake-IP&L	4	1	5
11	Small Power	921	70	991
12	Haleywest	1,589	435	2,024
13	Spokane-Upriver	2,003	-335	1,668
14	Black Creek Index Purchase	442	-31	410
15	Contract A	6,680	110	6,789
16	Contract B	6,132	613	6,745
17	Contract C	6,132	526	6,658
18	Contract D	6,953	603	7,556
19	CS2 Exchange	0	1,533	1,533
20	TRC Purpa Purchase	0	5,124	5,124
21	PPM Wind Purchase	3,186	-477	2,709
22	Total Account 555	78,313	30,080	108,393
	556 SYSTEM CONTROL & DISPATCH			
23	Microwave Charge	2	-2	0
24	BPA Power Factor Penalty Charge	150	433	583
25	Total Account 556	152	431	583
	557 OTHER EXPENSES			
26	Broker Commission Fees	78	30	108
27	Fixed-Price Gas Purchases	0	0	0
28	Total Account 557	78	30	108
	501 THERMAL FUEL EXPENSE			
29	Kettle Falls - Wood Fuel	8,095	2,121	10,216
30	Colstrip - Coal	10,683	4,151	14,834
31	Colstip - Oil	188	12	200
32	Total Account 501	18,966	6,284	25,251
	547 OTHER FUEL EXPENSE			
33	Coyote Springs Gas	59,394	27,875	87,269
34	Gas Transportation Charge	6,240	1,915	8,155
35	Rathdrum Gas	81	5,337	5,418
36	Northeast CT Gas	0	434	434
37	Boulder Park Gas	3,238	-1,052	2,186
38	Kettle Falls CT Gas	593	-504	88
39	Rathdrum Gas Storage Fee	480	-480	0
40	Total Account 547	70,026	33,524	103,551

565 TRANSMISSION OF ELECTRICITY BY OTHERS

Avista Corp.
Power Supply Pro Forma - Washington Jurisdiction
System Numbers - Authorized and 2007 Pro Forma

Line No.		Jan 06 - Dec 06 Authorized	Adjustment	Jan 07 - Dec 07 Normalized
41	WNP-3	772	19	791
42	Grant Transmission	0	519	519
43	Black Creek Wheeling	49	0	49
44	Wheeling for System Sales & Purchases	348	-103	245
45	PTP for Colstrip & Coyote	8,315	-677	7,638
46	BPA Townsend-Garrison Wheeling	1,245	-72	1,173
47	Avista on BPA - Borderline	1,689	444	2,133
48	Kootenai for Worley	32	0	32
49	Sagle-Northern Lights	0	77	77
50	Garrison-Burke	214	11	225
51	PGE Firm Wheeling	643	0	643
52	Total Account 565	13,307	218	13,525
	536 WATER FOR POWER			
53	Headwater Benefits Payments	752	-71	681
	550 RENTS			
54	Rathdrum Lease Payments	6,729	-6,729	0
	549 MISC OTHER GENERATION EXPENSE			
55	Rathdrum Municipal Payment	133	106	239
56	**TOTAL EXPENSE**	188,457	63,873	252,330
	447 SALES FOR RESALE			
57	Short-Term Market Sales	56,332	11,144	67,476
58	Peaker (PGE) Capacity Sale	1,800	0	1,800
59	Spokane Energy Service Fee - Peaker Sale	-63	-1	-64
60	Nichols Pumping Sale	3,327	1,060	4,387
61	BPA on AVA Load Following Revenue	272	-272	0
62	Kaiser DES	69	-7	62
63	Pend Oreille DES & Spinning	324	66	390
64	Northwestern Load Following	0	1,267	1,267
65	Total Account 447	62,061	13,257	75,318
	456 OTHER ELECTRIC REVENUE			
66	Spokane Energy Scheduling Services	48	16	64
67	Gas Not Consumed Sales Revenue	0	0	0
68	Total Account 456	48	16	64
	453 SALES OF WATER AND WATER POWER			
69	Upstream Storage Revenue	365	-130	235
	454 MISC RENTS			
70	Colstrip Rents	24	-5	19
71	**TOTAL REVENUE**	62,498	13,138	75,636
72	**TOTAL NET EXPENSE**	125,959	50,735	176,695
73	**Settlement/Compliance Filing Adjustments**	-397		
74	**TOTAL NET EXPENSE WITH ADJUSTMENTS**	125,562	51,132	176,695

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-06________

EXHIBIT NO._____(WGJ-3)

WILLIAM G. JOHNSON

REPRESENTING AVISTA CORPORATION

Avista Corp.
Brief Description of Power Supply Adjustments

Line No.

1 **Short-term Purchases** - Short-term purchases are normalized through use of the AURORA Dispatch Simulation Model. The pro forma value reflects the short-term purchases during the pro forma period from the dispatch simulation study.

2 **Rocky Reach** - The pro forma cost for Rocky Reach is based on Chelan PUD's budgeted expenses. Avista's costs are based on the Company's 2.9% share of total cost.

3 **Wanapum** - Pro forma costs are based on Grant County PUD's Power Cost Forecast for Wanapum. Avista's costs are based on the Company's 8.2% share of total cost.

4 **Wells** - Wells' costs are based on Douglas PUD's Power Purchaser's Pro-Forma Statement. Avista's costs are based on the Company's 3.5% share of total cost.

5 **Priest Rapids Products** - Priest Rapids pro forma costs include the purchase of a small percentage of the project output at project cost, a larger portion at market rates and a revenue credit for Avista's allocation of the project sold at market rates.

6 **Grant Displacement** - Grant Displacement is scheduled energy from Grant PUD that is priced at the BPA PF rate.

7 **Grant Revenue Credit** - Grant Revenue Credit is included in the Priest Rapids line item.

8 **Douglas Settlement** - Douglas Settlement is for a small (approx. 4 aMW) of power Avista purchases from Douglas PUD at a below-market rate.

9 **WNP-3** - Pro forma costs are based on the five-year average amount of energy and the midpoint rate for contract year 2005 through 2006 escalated at the five-year average escalation rate.

10 **Deer Lake-IP&L** - Pro forma expense is for power purchased from Inland Power to serve Avista customers.

11 **Small Power** - Pro forma costs are based on expected generation and pro forma period contract rates. (Contract details are provided in a CONFIDENTIAL workpaper).

12 **Haleywest** - This purchase is from the cogeneration plant at Plummer, Idaho. Pro forma costs are based on expected generation and pro forma period contract rates. This

contract expires September 2006, but expectation is that it will be extended at avoided cost rates. (Contract details are provided in a CONFIDENTIAL workpaper).

13 **Spokane-Upriver** - Pro forma expense is based on the new contract effective July 2004. Pro forma expense is based on a purchase on the net of pumping (at the plant) generation at a rate equal to the eight year levelized avoided cost included in the Company's 2003 Integrated Resource Plan.

14 **Black Creek Index Purchase** - Expense is for an October purchase at index prices less transmission expense and a margin.

15 **Contract A** - This is a power purchase for the period January 2007 through December 2010 (Contract details are provided in a CONFIDENTIAL workpaper).

16 **Contract B** - This is a power purchase for the period January 2007 through December 2010 (Contract details are provided in a CONFIDENTIAL workpaper).

17 **Contract C** - This is a power purchase for the period January 2007 through December 2010 (Contract details are provided in a CONFIDENTIAL workpaper).

18 **Contract D** - This is a power purchase for the period January 2007 through December 2010 (Contract details are provided in a CONFIDENTIAL workpaper).

19 **CS2 Exchange** - The CS2 exchange expense is for an arrangement where Avista has the option to deliver power at the Coyote Springs 2 bus and receive power at the Mid Columbia.

20 **TRC Purpa Purchase** - The TRC (Thompson River Cogen) purchase is a pending agreement to purchase power from a qualifying cogeneration facility.

21 **PPM-Stateline Wind Purchase** - Pro forma expense is for a ten-year purchase from a Northwest wind project. Expense is based on expected energy amount times the contract rate. (Contract details are provided in a CONFIDENTIAL workpaper).

22 **Total Account 555**

23 **Microwave Charge** - Contract ended in 2006.

24 **BPA Power Factor Penalty Charge** - As part of its 2002 Transmission Rate Case, BPA began charging interconnected control areas for reactive power supplied by BPA. Pro forma expense is based on recent BPA charges.

25 **Total Account 556**

26 **Broker Commission Fees** - Pro forma expense is associated with purchases and sales of electricity and natural gas fuel.

27 **Fixed Cost Gas Purchases** - This is the expense 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 is included in Account 547.

28 **Total Account 557**

29 **Kettle Falls Wood Fuel Cost** - Pro forma fuel expense is based on the generation of the Kettle Falls plant in the AURORA model simulation and the unit cost of fuel.

30 **Colstrip Coal Cost** - Pro forma fuel expense is based on the generation of the Colstrip plant in the AURORA model simulation and the unit cost of fuel.

31 **Colstrip Oil** - Pro forma expense is for start-up oil expense.

32 **Total Account 501**

33 **Coyote Springs Gas** - Pro forma expense is an output of the AURORA model simulation based on the unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

34 **Gas Transportation Charge** - This expense is for transportation of natural gas from AECO to the Coyote Springs 2 plant. Pro forma expense is based on transportation charges in Canada and from the Canadian Border (Kingsgate) and for the Coyote Springs lateral.

35 **Rathdrum Gas** - Pro forma expense is an output of the AURORA model simulation based on the unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

36 **Northeast CT Gas** - Pro forma expense is an output of the AURORA model simulation based on the unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

37 **Boulder Park Gas** - Pro forma expense is an output of the AURORA model simulation based on the unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

38 **Kettle Falls CT Gas** - Pro forma expense is an output of the AURORA model simulation based on the unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

39 **Rathdrum Gas Storage Fee** - Contract ended April 2005.

40 **Total Account 547**

41 **WNP-3 Transmission** - Pro forma WNP-3 wheeling is based on 32.22 MW at a rate of $2.02/kW/mo through Sep. 2007 and $2.12/kW/mo Oct through Dec 2007.

42 **Grant Transmission** - Expense is for transmission purchased from Grant PUD through Oct. 2007 and is offset by transmission revenue.

43 **Black Creek Wheeling** - Expense is for wheeling and shaping associated with the Black Creek power purchase.

44 **Wheeling for System Sales and Purchases** - Pro forma expense is short-term transmission purchases and is based on an average of the past five years.

45 **BPA PTP Wheeling for Colstrip and Coyote Springs 2** - This wheeling is for the transmission of 196 MW from Colstrip at the Garrison Substation and 222 MW from the Coyote Springs 2 plant to Avista's system. Pro forma expense is based on 418 MW of capacity at a rate of $1.504/kW/mo through Sep. 2007 and $1.579 Oct. through Dec. 2007.

46 **BPA Townsend-Garrison Wheeling** - This expense is for the transmission of Colstrip power from the Townsend Substation to the Garrison Substation.

47 **Avista on BPA Borderline** - This expense is to serve Avista load off of BPA transmission. Pro forma expense is based on Avista's borderline loads priced at BPA's NT transmission rates plus ancillary services cost and use of facilities charges.

48 **Kootenai for Worley** - This expense is for Avista load served using Kootenai PUD's facilities.

49 **Sagle-Northern Lights** - Expense is for transmission purchased from Northern Light Utility to serve Avista customers in northern Idaho.

50 **Garrison Burke** - Garrison Burke wheeling is an expense for the transmission of Colstrip energy above 196 MW from the Garrison Substation over Montana Power's transmission system to the interconnection of Montana and Avista at Burke. The pro forma expense is based on the five-year average expense.

51 **PGE Firm Wheeling** - PGE firm wheeling reflects the cost of transmission from the John Day Substation to COB (Intertie South) purchased from Portland General Electric. The pro forma expense is based on 100 MW at the current rate of $.53549/kW/mo.

52 **Total Account 565**

53 **Headwater Benefits Expense** - Pro forma expense is based on the expense for contract year September 2005 through August 2006.

54 **Rathdrum Lease Payments** - Pro forma expense is $0 because the Company purchased the plant in September 2006.

55 **Rathdrum Municipal Payment** - This includes a payment in Jan. 2007 of $155,240 and amortization of a $1 million payment in 1995 to the city of Rathdrum for mitigation related to the Rathdrum generating facility.

56 **Total Expenses** - Sum of Accounts 555, 556, 557, 501, 547, 656, 536, 550, 549 and 553.

57 **Short-Term Market Sales** - Short-term sales volumes and market prices are normalized through use of the AURORA model simulation. The pro forma value reflects short-term sales during the pro forma period.

58 **Peaker (PGE) Capacity Sale** - This pro forma revenue is based on 150 MW of capacity at a price of $1/kW/mo.

59 **Spokane Energy Service Fee** - This is an expense associated with the Peaker (PGE) Capacity Sale. The pro forma revenue reduction in Account 447 is $63,000, of which $48,000 is included as Spokane Energy Scheduling Service revenue in Account 456.

60 **Nichols Pumping Sale** - This is a sale of energy to other Colstrip Units 3 and 4 owners at the Mid Columbia index price. Pro forma revenue is based on 8 MW at the market price as determined by the AURORA model.

61 **BPA on Avista Load Following Revenue** - Revenue is included in transmission revenues.

62 **Kaiser DES** - This contract provides load control services to Kaiser's Trentwood plant. (Contract details are provided in a CONFIDENTIAL workpaper).

63 **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).

64 **Northwestern Load Following** - This contract provides load control services to Northwestern Energy. (Contract details are provided in a CONFIDENTIAL workpaper).

65 **Total Account 447**

66 **Spokane Energy Scheduling Services** - This revenue is for scheduling services provided to Spokane Energy to serve the Peaker (PGE) Capacity Sale. This revenue (except $15,000 retained to pay for administrative expenses related to servicing the contract) offsets the revenue reduction in Account 447.

67 **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 is included in Account 547.

68 **Total Account 456**

69 **Upstream Storage Revenue** - Pro forma revenue is based on the revenue for contract year September 2005 through August 2006.

70 **Colstrip Rents** - Pro forma revenue is based on expected revenue.

71 **Total Revenue** - Sum of Accounts 447, 456, 453 and 454.

72 **Total Net Expense** - Total expense minus total revenue.

73 **Settlement/Compliance Filing Adjustments** - This is the total level of adjustments approved in Docket Nos. UE-050482 and UG-050483 (Consolidated), Order No. 5 "Approving and Adopting Settlement Agreement With Conditions" dated December 21, 2005.

74 **Total Net Expense with Adjustments** - This is the total net expense including the Settlement/Compliance Filing Adjustments.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-06________

EXHIBIT NO._____(WGJ-4)

WILLIAM G. JOHNSON

REPRESENTING AVISTA CORPORATION

Avista Corp.
Market Purchases and Sales, Plant Generation and Fuel Cost Summary
Proforma January 2007 - December 2007

	Total	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-04	Oct-04	Nov-04	Dec-04
		744	672	744	719	744	720	744	744	720	745	720	744
Market Sales - Dollars	-$67,476,020	-$3,982,867	-$5,445,666	-$2,791,110	-$9,480,845	-$10,128,139	-$10,088,585	-$5,668,178	-$2,463,987	-$4,546,415	-$1,778,800	-$4,043,734	-$7,057,694
Market Sales - MWh	(1,250,811)	-49,136	-70,360	-44,683	-167,263	-257,736	-268,387	-129,496	-35,699	-59,714	-26,120	-54,432	-87,788
Average Market Sales Price -$/ MWh	$53.95	$81.06	$77.40	$62.46	$56.68	$39.30	$37.59	$43.77	$69.02	$76.14	$68.10	$74.29	$80.40
Market Purchases - Dollars	$36,863,500	$5,420,321	$2,373,099	$4,629,046	$400,289	$159,346	$176,948	$1,740,067	$5,385,226	$3,602,277	$5,112,254	$3,205,463	$4,659,165
Market Purchases - MWh	522,097	78,020	32,868	63,290	8,729	3,474	4,441	33,671	77,464	49,406	71,685	39,651	59,400
Average Market Purchase Price - $/MWh	$70.61	$69.47	$72.20	$73.14	$45.86	$45.87		$51.68	$69.52	$72.91	$71.32	$80.84	$78.44
Net Market Purchases (Sales) MWh	-728,714	28,885	-37,492	18,607	-158,535	-254,262	-263,946	-95,825	41,765	-10,308	45,565	-14,780	-28,388
Net Market Purchases (Sales) aMW	-83	39	-56	25	-220	-342	-367	-129	56	-14	61	-21	-38
Average Sale and Purchase Price - $/MWh	$58.85	$73.95	$75.74	$68.72	$56.15	$39.38	$37.63	$45.40	$69.36	$74.68	$70.46	$77.05	$79.61
Colstrip MWh	1,604,948	150,388	137,700	140,253	96,680	81,884	96,416	130,737	157,084	152,781	155,771	151,731	153,524
Colstrip Fuel Cost $/MWh	$9.24	$9.24	$9.24	$9.24	$9.24	$9.24	$9.24	$9.24	$9.24	$9.24	$9.24	$9.24	$9.24
Colstrip Fuel Cost	$14,834,270	$1,390,011	$1,272,739	$1,296,335	$893,594	$756,837	$891,155	$1,208,383	$1,451,897	$1,412,133	$1,439,764	$1,402,425	$1,418,997
Kettle Falls MWh	376,317	33,429	30,161	33,347	32,222	33,171	15,515	33,252	33,491	32,450	33,469	32,359	33,451
Kettle Falls Fuel Cost $/MWh	$27.15	$24.82	$25.15	$26.14	$27.60	$27.88		$27.89	$27.68	$27.82	$27.98	$27.88	$27.31
Kettle Falls Fuel Cost	$10,216,430	$829,624	$758,498	$871,758	$889,312	$924,747	$432,939	$927,438	$927,009	$902,913	$936,587	$902,118	$913,486
Coyote Springs MWh	1,390,544	146,689	119,638	116,581	92,345	40,819	57,236	90,598	142,264	152,124	146,437	137,954	147,859
Coyote Springs Fuel Cost $/MWh	$62.76	$68.27	$69.11	$68.24	$60.16	$58.73	$59.59	$58.05	$57.87	$57.95	$59.14	$63.03	$67.68
Coyote Springs Fuel Cost	$87,269,141	$10,013,796	$8,268,404	$7,955,270	$5,555,200	$2,397,253	$3,410,533	$5,259,280	$8,232,102	$8,815,381	$8,659,734	$8,695,093	$10,007,095
Boulder Park MWh	26,351	2,027	2,275	2,055	2,419	1,418	712	952	2,515	2,824	2,873	3,322	2,959
Boulder Park Fuel Cost $/MWh	$82.95	$91.39	$91.15	$89.82	$76.04	$74.66	$75.12	$76.93	$77.69	$78.23	$79.14	$84.32	$90.71
Boulder Park Fuel Cost	$2,185,928	$185,259	$207,375	$184,610	$183,937	$105,886	$53,459	$73,228	$195,354	$220,922	$227,373	$280,109	$268,417
Kettle Falls CT MWh	1,089	231	188	31	149	36	7	37	162	96	39	25	87
Kettle Falls CT Fuel Cost $/MWh	$81.25	$87.94	$87.92	$86.40	$73.40	$71.70	$72.98	$74.87	$75.12	$74.90	$75.35	$81.29	$89.01
Kettle Falls CT Fuel Cost	$88,461	$20,349	$16,505	$2,656	$10,955	$2,564	$517	$2,736	$12,191	$7,221	$2,940	$2,046	$7,780
Rathdrum MWh	51,272	5,258	5,397	2,940	4,620	2,316	1,109	1,586	4,654	4,702	5,386	5,988	7,316
Rathdrum Fuel Cost $/MWh	$105.67	$115.62	$115.18	$113.26	$96.04	$94.01	$95.08	$97.20	$98.28	$98.69	$99.53	$106.16	$114.97
Rathdrum Fuel Cost	$5,417,860	$607,989	$621,659	$332,997	$443,650	$217,732	$105,449	$154,106	$457,417	$464,052	$536,093	$635,640	$841,075
Northeast MWh	3,587	551	703	151	349	132	51	60	317	245	256	209	564
Northeast Fuel Cost $/MWh	$121.02	$129.30	$129.32	$126.99	$107.94	$105.07	$107.41	$109.88	$110.84	$111.16	$111.02	$119.55	$130.31
Northeast Fuel Cost	$434,145	$71,180	$90,868	$19,227	$37,665	$13,853	$5,494	$6,605	$35,083	$27,211	$28,409	$25,010	$73,521
Total Fuel Expense	$120,446,235	$13,118,208	$11,236,068	$10,662,853	$8,014,314	$4,418,871	$4,899,546	$7,631,776	$11,311,052	$11,849,833	$11,830,901	$11,942,441	$13,530,371
Net Fuel and Purchase Expense	$89,833,715												

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-06________

EXHIBIT NO._____(WGJ-5)

WILLIAM G. JOHNSON

REPRESENTING AVISTA CORPORATION

Avista Corp.
Energy Recovery Mechanism
Proposed Power Supply Expense, Transmission Expense and Revenue, and Retail Sales

ERM Power Supply Expense

	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Purchaed Power - Acct 555	108,392,826	12,923,228	9,405,902	10,965,867	6,585,639	5,264,016	4,980,019	6,651,001	10,271,710	8,388,088	10,439,209	10,395,093	12,123,054
Thermal Fuel - Acct 501	25,250,700	2,236,301	2,047,904	2,184,760	1,799,573	1,698,251	1,340,761	2,152,488	2,395,573	2,331,712	2,393,018	2,321,210	2,349,150
Natural Gas Fuel - Acct 547	103,550,193	11,413,332	9,899,383	9,189,313	6,925,961	3,431,840	4,270,005	6,190,477	9,626,668	10,229,310	10,149,072	10,332,420	11,892,411
Sales for Resale - Acct 447	75,317,764	4,778,379	6,180,698	3,531,968	10,109,375	10,638,615	10,565,393	6,232,363	3,188,392	5,256,712	2,400,526	4,715,239	7,720,105
Broker Fees	108,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000
Net Power Supply Expense	161,983,954	21,803,482	15,181,491	18,816,972	5,210,798	-235,508	34,392	8,770,603	19,114,559	15,701,399	20,589,773	18,342,484	18,653,509
ERM Transmission Expense	13,525,450	1,131,803	1,130,923	1,131,803	1,128,014	1,128,320	1,128,026	1,128,320	1,128,320	1,128,026	1,188,101	1,086,751	1,087,044
ERM Transmission Revenue	9,892,740	847,493	847,889	848,238	847,122	848,187	847,461	847,669	849,420	847,966	846,799	719,671	694,824

Washington ERM Retail Sales, kWh

	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Schedule 1	2,369,814,816	288,891,426	233,551,231	230,312,140	196,150,377	162,191,414	151,921,294	154,548,835	174,077,237	163,652,262	171,526,894	179,961,866	263,029,839
Schedule 11/12	419,172,101	41,588,861	38,353,630	37,049,672	34,040,115	31,046,446	30,337,673	31,611,840	33,375,227	33,830,615	33,410,559	32,666,774	41,860,688
Schedule 21/22	1,568,071,363	135,788,063	131,744,693	129,228,304	123,606,584	123,827,406	129,157,927	118,810,043	134,577,612	135,667,649	140,951,968	126,554,410	138,156,702
Schedule 25	995,710,203	83,794,799	82,076,393	76,974,205	80,550,248	81,334,167	82,879,005	84,101,985	88,099,640	85,869,160	81,958,788	84,095,399	83,976,415
Schedule 31/32	121,950,109	3,708,266	3,848,351	3,611,633	4,884,507	8,978,574	13,456,597	18,523,921	22,340,857	20,809,903	12,649,572	5,469,590	3,668,338
Schedules 41 - 49	27,361,858	2,300,859	2,278,737	2,327,157	2,275,808	2,274,385	2,272,359	2,273,095	2,279,286	2,270,781	2,266,423	2,272,332	2,270,636
Total kWhs	5,502,080,450	556,072,274	491,853,035	479,503,111	441,507,640	409,652,392	410,024,855	409,869,719	454,749,860	442,100,370	442,764,205	431,020,371	532,962,619
Adj to Calendar		-8,150,708	-26,838,248	13,127,776	-26,608,255	2,308,488	-3,897,127	41,519,760	12,501,699	-32,463,979	11,797,690	18,965,643	-2,262,739
Calendar 2007 PF Load	5,502,080,450	547,921,566	465,014,786	492,630,887	414,899,385	411,960,880	406,127,728	451,389,479	467,251,559	409,636,391	454,561,895	449,986,014	530,699,879