BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-_____

DIRECT TESTIMONY OF WILLIAM G. JOHNSON

REPRESENTING AVISTA CORPORATION

Exhibit T- _____ (WGJ-T)

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 East 1411 Mission Avenue, Spokane, Washington, and the Company employs me 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 Power Contracts 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 long-term resource planning issues.

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

A. My testimony will 1) describe the adjustments to the 2000 test period power supply revenues and expenses, and 2) describe the methodology of a power cost adjustment mechanism the Company is proposing. Specifically, my testimony will cover the following areas:

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

A. Yes. I am sponsoring Exhibit No(s). _____ (WGJ-1) through _____ (WGJ-3) as previously marked for identification, 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 is providing testimony describing the Prosym Model used to normalize hydroelectric and thermal generation and short-term purchase and sales transactions. Also, Mr. McKenzie is providing testimony that addresses the procedures and related accounting issues associated with a proposed temporary deferred accounting mechanism and power cost adjustment proposal.

II. Summary

Q. Please provide an overview of your direct testimony.

A. My testimony explains adjustments made to normalize power supply revenue and expense items in the proforma period compared to the 2000 test period. This involves estimating revenues and expenses based on normal streamflow and weather conditions, and expected market power prices. In addition, adjustments are made to reflect known and measurable power contract changes between the 2000 test period, and the time period that retail rates will be in effect, i.e., the proforma period beginning November 1, 2002 and ending October 31, 2003. The net effect of my adjustments to the 2000-test period power supply net expense is a decrease of $200,816,000 on a system basis. The Washington portions of this adjustment is $133,119,000, which is incorporated into the revenue requirement calculation for the Washington jurisdiction by Witness Falkner.

My testimony then describes the methodologies proposed by the Company for a temporary deferred accounting mechanism for the period January 2002 through October 2002, and a power cost adjustment to be in place beginning November 2002.

III. Proforma 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 ____ (WGJ-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, wheeling expenses, thermal fuel expenses and other miscellaneous power supply revenues and expenses.

Q. What is the basis for the adjustments to the 2000 actual power supply revenues and expenses?

A. Adjustments are made to set the revenues and expenses based on normal weather, and normal streamflows and expected wholesale market conditions. The Prosym Model accomplishes this task. The Prosym Model dispatches Company resources on an hourly basis and calculates the optimum level of generation from the Company's thermal resources along with the short-term purchases and sales required to serve system requirements. Mr. Kalich explains the operation and the results from the Prosym Model.

Adjustments are also made to reflect known and measurable contract changes between the 2000 test period and the proforma period. The Company has included proforma power supply adjustments to reflect power costs for the twelve-month period beginning November 1, 2002 and ending October 31, 2003.

Q. What changes has the Company made in the calculation of normal power supply costs from the prior general rate case?

A. The primary change has been the development of a new hourly system simulation model. This model calculates the optimum dispatch of Company resources in each hour of the year for every water year included in the period of record. The average generation and costs for each month over all the water years in the study is then used to

determine the normal level of power supply costs. This model directly incorporates the flexibility of the Company's resources to meet system obligations. This flexibility includes the ability of the Company's hydro resources to increase or decrease generation on an hourly basis in response to changes in system obligations. It also models the Company's ability to change generation levels at its thermal resources to meet load obligations or maximize their value in the energy marketplace. This is a significant change and improvement over the Company's Monthly Dispatch Model used in prior rate cases, which only calculated obligations and resources on an average monthly energy basis, and could not explicitly model the hourly flexibility of the Company's resources.

Power supply adjustments for known and measurable changes have been prepared using the same methods that have been used in prior general rate cases. Detailed work papers have been provided to the Commission that support each of the proforma adjustments. A brief description of each adjustment is also included in Exhibit _____(WGJ-1).

Short-Term Purchases and Sales

Q. How are the short-term purchases (Account 555) and sales (Account 447) determined in the proforma?

A. Short-term purchases and sales are an output of the Prosym Model. They are the average of purchases and sales made to balance the system obligations and resources. Mr. Kalich explains how the Prosym Model determines the short-term transactions. Exhibit _____(WGJ-2) shows the proforma monthly short-term purchases and sales.

Q. Do short-term transactions include any commercial trading activity, i.e., transactions made outside of the optimal dispatch of system resources?

A. No they do not. The short-term transactions included in the proforma represent the optimal dispatch of Company resources given the level of obligations and resources and fuel and electricity prices included in the proforma. Resources are economically dispatched against market prices and market sales are included in short-term sales revenue.

Potlatch Direct Assignment Credit

Q. What is the Potlatch direct assignment credit?

A. Under the current contract, Potlatch revenue is allocated to both states in the same manner as system power supply expense is allocated to both states. It is anticipated that a new contract with Potlatch will not have allocated revenue, and that revenue will be directly assigned to the Idaho jurisdiction. The intent of the Potlatch direct assignment credit in the proforma is to reduce the financial impact on Washington customers from a change in Avista's contract with Potlatch.

The proforma assumes that the Company no longer purchases power from Potlatch's co-generation facility. The Potlatch Co-Gen line item in Account 555 is therefore $0. Instead, Potlatch is assumed to generate 50 aMW to offset their load requirement. Potlatch's remaining load is part of Avista's system load requirement. Mr. Hirschkorn explains the proposed treatment of a new contract with Potlatch.

Q. How is the Potlatch direct assignment credit determined?

A. The credit is calculated by multiplying 25 MW of energy each month by the weighted average price of short-term purchases and sales. Potlatch's load is roughly 93 average MW. The proforma assumes that Potlatch generates 50 aMW into their own load, which reduces system load obligation by 50 aMW. The 2000 test year load has been reduced by 50 average MW in the proforma calculations. That leaves roughly 43 aMW of Potlatch load to be served by system resources. Crediting the proforma with a 25 aMW reduction in expense effectively reduces the system requirement to serve

Potlatch load to 18 average MW (93 aMW load – 50 aMW self generation – 25aMW Direct Assignment Credit) for the Washington jurisdiction. As explained by witness Hirschkorn, this level of obligation results in approximately no net impact to Washington customers as compared to the existing Potlatch contract.

Q. Do the results of the proforma change if Potlatch does not generate to serve their own load?

A. No. The results of the proforma would not change if Potlatch does not generate to serve their own load.

Mid Columbia Purchase Cost

Q. How are expenses for the Mid Columbia purchase contracts determined in the proforma?

A. Wanapum and Priest Rapid's expenses are based on Grant County PUD's power cost forecast for 2002 and 2003 dated October 3, 2001. The proforma cost for Rocky Reach is based on Chelan County PUD's projections of 2002 debt service costs and O&M expenses. Wells' costs are based on a Douglas PUD's Power Purchaser's Pro-Forma Statement for the period September 1, 2001 to August 31, 2002. These forecasts are currently the best estimates of costs during the proforma period and these forecasts have been consistently used in prior cases for these expenses.

Long-Term Contract Changes

Q. What are the primary adjustments to long-term contracts in the proforma?

A. Almost all of the Company's medium to long term contracts (2 to 15 years) expire prior to or during the proforma period. The result is that, excluding the reduction in short-term purchases, Account 555, Purchased Power, decreases by $281 million in the proforma compared to the 2000 test year. At the same time, Account 447,

Sales for Resale decreases by $312 million in the proforma. The Company's remaining power purchases include TransAlta, WNP-3, and small power and Purpa purchases. Remaining long-term sales include the last two months of the Puget sale, the last year of the PacifiCorp summer sale, the Enron capacity sale, the Nichols pumping sale and two load following and reserves sales.

The WNP-3 power purchase expense is based on the expected level of power deliveries from BPA, which is determined by the equivalent availability factors of the surrogate nuclear plants used a proxy for the WNP-3 plant. The WNP-3 rate used in the proforma is the midpoint of the ceiling and floor rates, per the WNP-3 agreement. Additional information related to the long-term contracts is provided in Exhibit _____(WGJ-1).

Capacity Purchase

Q. What expense is included in the proforma for capacity purchases?

A. The proforma expense for capacity purchases is $0. In the 2000 test year capacity purchases totaled $2,874,000. These purchases consisted of two types of capacity, exchange capacity and reserve capacity. Exchange capacity is where Capacity and energy is received during higher load times and returned during lower load periods. Reserve capacity is capacity that is purchased to ensure energy deliveries during periods when the availability of market energy may be limited.

The Company currently does not have any long-term contracts for either exchange capacity or reserve capacity purchases. As explained by Mr. Kalich, the hourly pricing used in the Prosym Model incorporates a capacity value, and as such capacity expenses are included in the short-term energy purchases.

Proforma Fuel Costs

Q. How are proforma fuel costs determined?

A. Proforma monthly fuel costs are calculated by the Prosym Model. Fuel costs are the average monthly fuel cost for each plant over the period of record. Natural gas fuel unit costs are based on forward market prices that were varied depending on the water year as explained by witness Kalich. Total natural gas fuel costs for each plant are based on the unit fuel cost and the plant's level of generation. Each month's total fuel cost is then averaged over the period of record to determine the proforma fuel expense.

The fuel costs for the other, non natural gas fuel plants, Colstrip and Kettle Falls were determined in a similar fashion. For these two plants the unit fuel cost does not vary depending on the water year. 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. Total fuel costs for each plant are based on the unit fuel cost and the plant's level of generation. Each month's total fuel cost is then averaged over the period of record to determine the proforma fuel expense. Exhibit _____(WGJ-2) shows the proforma fuel costs by month for each plant.

Contracts Tied to Market Based Electric and Gas Prices

Q. What type of contracts are tied to market based electric and gas prices?

A. Avista has one purchase that is priced at the market electric price, one sale priced at the market electric price and one sale where the energy rate is based on the market price of natural gas. Avista purchases 11 MW in August from Black Creek Hydro at the Dow Jones Mid Columbia index price. The Nichols pumping sale is also priced at the Dow Jones Mid Columbia index. The energy rate of the PacifiCorp summer sale is based on the market price of gas and a specified heat rate to convert the gas price to an electric price.

The proforma power supply expense uses the weighted average short-term purchase and sales prices determined by the Prosym Model as the proxy for the Mid Columbia index electric price. The gas price used to determine the energy rates in the

PacifiCorp contract is the market price of gas from the Prosym Model. By using the modeled electric and gas prices to determine the market based contracts, there is consistency between the revenues and expenses of these contracts with the short-term purchase expense and sales revenue included in the proforma.

Transmission Expense

Q. What factors are driving the increase in transmission expense in the proforma?

A. Transmission expense in Account 565 increases by $1.2 million over the test year. The reason for the increased expense is additional amounts of transmission purchased in the proforma period and a 24.3% increase in BPA's transmission rates. The amount of primary transmission purchased by the Company to integrate generation increases by 269 megawatts, 140 megawatts for Coyote Springs II plant and an additional 129 megawatts to wheels the TransAlta purchase from the Paul substation to the Avista's system. Currently the Company purchases 267 megawatts of BPA point to point transmission, 196 megawatts for Colstrip and 71 megawatts for TransAlta. Coyote Springs II requires another 140 megawatts and TransAlta another 129 Mw (71 MW + 129 MW = 200 MW Purchase). The cost of this additional transmission is approximately $4 million per year (269,000 kW x $1.243/kW/mo x 12 month). The BPA transmission rate increase totals an additional $779,000 (267,000 kW x ($1.243/kW/mo - $1.00/kW/mo x 12 months).

The Company has two larger transmission related expenses that terminate prior to the proforma period. Transmission (Account 565) expenses are reduced by $3 million due to the expiration of the Cogentrix Use of Facilities contract that expired September 30, 2001 and the Clark Service Fee, which was part of the 5 year sale to Clark that expired July 31, 2001. The wheeling expense for short-term sales and purchases is set at $0 in the proforma.

Overall, despite the need to purchase an additional 269 MW of point-to-point transmission (increased cost of $4,012,404) and a 24.3% increase in BPA's transmission rate (increased cost of $778,572), the overall increase in the proforma transmission expense (Account 565) is only $1.2 million.

IV. Description of Temporary Deferral Accounting Mechanism

Q. What type of temporary deferred accounting mechanism is the Company proposing for the period January 2002 through October 2002?

A. The Company is proposing to use a deferral calculation methodology similar to the current methodology, but with an important change. Like the current deferral mechanism, the proposed methodology would compare the actual and authorized amounts in FERC accounts 555 (Purchased Power), 501 and 547 (Fuel) and 447 (Sales for Resale) to compute the change in power supply expense, and would include the fixed costs of the new small generation resources such as Boulder Park and the Coyote Springs II project when it comes online in June 2002. The methodology would also include a retail revenue adjustment to account for the revenue offset to the power supply costs. An important change to the methodology is that the Company proposes that only 90% of the change in net power supply expense be deferred.

The mechanism would calculate the change in total net expense of power supply to serve system obligations. The change in total net expense includes the difference between actual and authorized levels of the four FERC accounts, natural gas or diesel fuel expenses not captured in the FERC accounts and the fixed costs associated with the Company's new generation resources. It is necessary to make an adjustment to include the cost of natural gas fuel that is purchased but not consumed at a generation plant, because for accounting purposes it is not included in Account 547 Other Fuel Expense. In the case where gas is purchased and resold, the expense is included in Account 557 and

supply expense. Fuel expense not included in account 547 would be added to derive the total change in power supply expense. This system change in power supply expense is then multiplied by the Washington allocation. From the Washington change in power supply expense the Washington retail revenue adjustment is subtracted to derive the Washington change in total net expense. The Washington change in total net expense is multiplied times 90% to determine the monthly PCA entry. Positive PCA entries are in the surcharge direction, and negative PCA entries are in the rebate direction. The calculation of the monthly PCA entries is as follows:

Power Cost Adjustment
Monthly PCA Entry Calculation

=	Actual Power Supply Expense for FERC Accounts
-	Authorized Power Supply Expense for FERC Accounts
=	Change in Power Supply Expense
+	Fuel Expense not included in Account 547
x	Washington Allocation %
=	Washington Change in Power Supply Expense
+	Washington Retail Revenue Adjustment
=	Washington Change in Total Net Expense
x	90% Sharing
=	**Washington Power Cost Adjustment Entry**

Q. How would the actual power supply expense be calculated in the PCA mechanism?

A. The actual power supply expense would be calculated by summing FERC accounts 555 (Purchased Power), accounts 501 (Fuel) and 547 (Fuel), and a line item for the expense of fuel not included in account 547, as discussed earlier, and subtracting FERC account 447 (Sales for Resale).

Q. Why are only the four FERC accounts included in the PCA mechanism?

A. As explained by Mr. Norwood, these four accounts include the power supply expenses that have the greatest volatility and are subject to uncontrollable factors, such as weather and market prices. Other power supply accounts cover areas such as

transmission expense and revenues, other expenses and revenues such as headwater benefits expense and revenue, and rents. Expenses and revenues in these accounts are, for the most part, much less volatile and don't vary due to weather or market price changes.

Q. Why are there fuel costs not included in account 547?

A. This expense (or gain) reflects the expense the Company incurs to sell gas that was purchased for the combustion turbine plants. This line item is necessary because under FERC accounting rules the Company cannot book fuel expenses in Account 547 if the fuel was not consumed. Because the Company at times may sell off some of the gas or diesel purchased for the gas or diesel fueled plants, the purchase expense and sales revenue of the gas is recorded in other accounts (456 revenue and 557 expense). The expense to be included in the PCA is the gain or loss the Company incurred from the resale of the gas or diesel.

Q. How would the authorized power supply expense be determined?

A. The authorized power supply expense would include the expense and revenues in each of the four FERC accounts included in the final order on Avista's general rate case.

Retail Revenue Adjustment

Q. Why does the PCA mechanism include a retail revenue adjustment?

A. Increased retail load results in increased power supply costs. Likewise, reduced retail loads result in reduced power supply costs. If retail loads are higher than what was used to calculate authorized power supply expenses, then increased retail revenues should be recognized as an offset to the increased power supply expenses.

As explained by Mr. McKenzie, if the difference between actual and authorized retail revenue is an increase, then that increase adjusted for distribution costs to serve load growth is used to offset increased power supply costs resulting from serving

increased retail loads. Likewise, if the difference between actual and authorized retail revenue is a decrease, then that decrease adjusted for distribution costs to serve load growth is used to offset reduced power supply costs resulting from serving reduced retail loads.

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

A. Yes.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-_____

EXHIBIT NO. ____ (WGJ-1)

PROFORMA POWER SUPPLY EXPENSE

Avista Corp.
Power Supply Proforma - Washington Jurisdiction
System Numbers - 2000 Actual and Nov 02 - Oct 03 Proforma

Water Years	60
Coyote Springs	50%
Potlatch Self Generation	50 MW

Line No.		Jan 00 - Dec 00 **Actuals** ($000)	Adjustment	Nov 02 - Oct 03 **Proforma** ($000)
	555 PURCHASED POWER			
1	Short-Term Market Purchases	$734,774	-$721,211	$13,563
2	Potlatch Direct Assignment Credit	$0	-$7,087	-$7,087
3	Rocky Reach	1,742	130	1,872
4	Wanapum	2,917	502	3,419
5	Priest Rapids	1,799	97	1,896
6	Wells	1,042	127	1,169
7	TransAlta	26,423	10,316	36,739
8	WNP-1 Reshape	5,273	-5,273	0
9	WNP-3	10,946	1,513	12,459
10	Entitlemnt & Sup Cap	25	-17	8
11	Deer Lake-IP&L	3	0	3
12	Small Power	1,370	-61	1,309
13	Hydro-Tech	221	28	249
14	WPI Amort	989	-989	0
15	Spokane-Upriver	2,095	362	2,457
16	Potlatch Co-Gen	23,360	-23,360	0
17	Capacity Purchases	2,874	-2,874	0
18	ESI 4-yr	6,434	-6,434	0
19	Enron - Backs Cowlitz	4,335	-4,335	0
20	Enron 2-yr	10,826	-10,826	0
21	Sempra - 5 yr	3,306	-3,306	0
22	MIECO Purchase	5,007	-5,007	0
23	Rathdrum Turbine Gas Swap	81	-81	0
24	Black Creek Index Purchase	1,383	-1,068	315
25	BPA 115 MW purch	21,668	-21,668	0
26	Cinergy 3 yr Purchase	2,118	-2,118	0
27	Non-Monetary	18,650	-18,650	0
28	PacifiCorp Wind	2	-2	0
29	Duke Index Purchase	107,284	-107,284	0
30	Idaho Index Purchase	73,796	-73,796	0
31	Total Account 555	1,070,743	-1,002,373	68,370
	556 SYSTEM CONTROL & DISPATCH			
32	Microwave Charge	24	-24	0
33	Metering Amortization Cost	119	63	182
34	Total Account 556	143	39	182
	557 OTHER EXPENSES			
35	Broker Commission Fees	198	-168	30
36	Hedge Services	-72	72	0
37	Rathdrum Service Fee	2	-2	0
38	Mark-to-Market Restate	197	-197	0
39	Clark Contract Buydown	888	-888	0
40	PSE Exchange	279	-279	0
41	Reserves for Uncollectables	512	-512	0
42	Rathdrum Gas Storage Optimization Expense	1,187	-1,187	0
43	Total Account 557	3,191	-3,161	30
	501 THERMAL FUEL EXPENSE			
44	Kettle Falls - Wood Fuel	3,694	175	3,869
45	Kettle Falls - Gas	226	-226	0
46	Centralia - Coal	10,058	-10,058	0
47	Colstrip - Coal	11,019	785	11,804
48	Centralia - Oil	34	-34	0

Avista Corp.
Power Supply Proforma - Washington Jurisdiction
System Numbers - 2000 Actual and Nov 02 - Oct 03 Proforma

Water Years	60
Coyote Springs	50%
Potlatch Self Generation	50 MW

Line No.		Jan 00 - Dec 00 **Actuals** ($000)	Adjustment	Nov 02 - Oct 03 **Proforma** ($000)
49	Colstip - Oil	178	-73	105
50	Total Account 501	25,209	-9,432	15,777
	547 OTHER FUEL EXPENSE			
51	Coyote Springs Gas	0	19,213	19,213
52	Rathdrum Gas	39,600	-32,368	7,232
53	Northeast CT Gas	2,399	-1,163	1,236
54	Boulder Park Gas	0	2,262	2,262
55	Kettle Falls CT Gas	0	508	508
56	Fuel Cell Project Gas	54	-54	0
57	NE Combustion Turbine - Oil	70	-70	0
58	Rathdrum Gas Storage Fee	695	-215	480
59	Total Account 547	42,818	-11,886	30,932
	565 TRANSMISSION OF ELECTRICITY BY OTHERS			
60	WNP-3	545	132	677
61	CSPE	15	-10	5
62	Black Creek Wheeling	54	-5	49
63	Supplemental Capacity Wheeling	3	-2	1
64	Wheeling for Short-term Sales & Purchases	835	-835	0
65	Garrison/Paul PTP	3,207	2,700	5,907
66	BPA Townsend-Garrison Wheeling	1,178	0	1,178
67	Garrison-Burke	180	134	314
68	Cogentrix Use of Facilities	925	-925	0
69	Clark Service Fee	2,075	-2,075	0
70	PGE Firm Wheeling	1,017	0	1,017
71	Coyote Springs Transmission	0	2,088	2,088
72	Total Account 565	10,034	1,202	11,236
	536 WATER FOR POWER			
73	Headwater Benefits	695	-36	659
	550 RENTS			
74	Rathdrum Lease Payments	4,546	-4	4,542
	549 MISC OTHER GENERATION EXPENSE			
75	Rathdrum Municipal Payment	133	0	133
	553 MISC OTHER GENERATION EXPENSE			
76	Rathdrum Incremental Maintenance	-859	859	0
	0928 FERC FEES ADMIN			
77	FERC Fees	318	-318	0
78	**TOTAL EXPENSE**	1,156,971	-1,025,110	131,861
	447 SALES FOR RESALE			
79	Short-Term Market Sales	538,102	-502,035	36,067
80	Puget #2	15,337	-14,174	1,163
81	Seattle High Ross	175	-175	0
82	Enron Capacity Sale	1,800	0	1,800
83	PGE Monetization Amortization	7,371	-7,371	0
84	Cogentrix 57 month	16,540	-16,540	0
85	PacifiCorp 1994	6,784	1,324	8,108
86	EWEB	1,564	-1,564	0
87	Clark #2 5-YR	26,972	-26,972	0

Avista Corp.
Power Supply Proforma - Washington Jurisdiction
System Numbers - 2000 Actual and Nov 02 - Oct 03 Proforma

Water Years	60
Coyote Springs	50%
Potlatch Self Generation	50 MW

Line No.		Jan 00 - Dec 00 **Actuals** ($000)	Adjustment	Nov 02 - Oct 03 **Proforma** ($000)
88	Snohomish 10-yr	18,039	-18,039	0
89	W. Kootenay	488	-488	0
90	City of Cheney	281	-281	0
91	Pend Oreille 2yr	517	-517	0
92	Cowlitz - Backed by Enron Purchase	4,424	-4,424	0
92	Nichols Pumping Sale	6,118	-4,404	1,714
93	Montana Index Sale	107,643	-107,643	0
94	Duke Index Sale	108,944	-108,944	0
95	Cogentrix DES	1,410	-1,321	89
96	Pend Oreille DES & Spinning	303	-31	272
97	Sovereign DES	277	-277	0
98	Long Term Prior Period Adj.	-57	57	0
99	Total Account 447	863,032	-813,819	49,213
	456 OTHER ELECTRIC REVENUE			
100	Scheduling Services	12	-12	0
101	Skookumchuck Hydro	99	-99	0
102	Illinova Exchanges	138	-138	0
103	Cogentrix Use of Facilities	925	-925	0
104	Kaiser Power Mgmt Services	244	-244	0
105	PGE Service Fee	47	-47	0
106	Puget Storage Fee	187	-187	0
107	TECWA Exchange	74	-74	0
108	Colstrip Sale of Lots	11	-11	0
109	Options Revenue	5,694	-5,694	0
110	SCL Exchange	21	-21	0
111	Kaiser Transmission Credit	1,657	-1,657	0
112	Rathdrum Gas Storage Optimization Revenue	1,331	-1,331	0
113	Total Account 456	10,440	-10,440	0
	453 SALES OF WATER AND WATER POWER			
114	Upstream Storage Revenue	453	-34	419
	454 MISC RENTS			
115	Colstrip Rents	66	-66	0
116	**TOTAL REVENUE**	873,991	-824,293	49,632
117	**TOTAL NET EXPENSE**	282,980	-200,816	82,230
	FUEL-TONS			
118	Kettle Falls	569,947	-289,090	280,857
119	Centralia	321,780	-321,780	0
120	Colstrip	934,476	192,703	1,127,179
	FUEL-COST PER TON			
121	Kettle Falls	6.48	7.29	13.77
122	Centralia	31.26		
123	Colstrip	11.79	-1.32	10.47

Avista Corp.
Brief Description of Power Supply Adjustments

Line No.

1 **Short-term Purchases** - Short-term purchases are normalized through use of the Prosym Model as explained in Mr. Kalich's testimony. The proforma value reflects the average short-term purchases from the dispatch simulation study.

2 **Potlatch Direct Assignment Credit** – This credit is the cost for a 25 MW purchase at the average modeled energy price of $32.36/MWh. This expense is directly assigned to the Idaho jurisdiction to cover the cost of serving the remaining Potlatch load. It is a credit to account 555 Purchased Power, effectively reducing system load requirements by 25 aMW.

3 **Rocky Reach** - The proforma cost for Rocky Reach is based on Chelan County PUD's projections of debt service costs and O&M expenses. . Avista's costs are based on the Company's 2.9% share of total cost.

4 **Wanapum** - Proforma costs are based on Grant Count PUD's September 21, 2001 Power Cost Forecast. Avista's costs are based on the Company's 8.2% share of total cost.

5 **Priest Rapids** - Priest Rapids proforma costs are based on Grant Count PUD's September 21, 2001 Power Cost Forecast. Avista's costs are based on the Company's 6.1% share of total cost.

6 **Wells** - Wells' costs are based on Douglas PUD's Power Purchaser's Pro-Forma Statement for the period September 1, 2001 to August 31, 2002. Avista's costs are based on the Company's 3.5% share of total cost.

7 **TransAlta** - Proforma costs are based on a 200 MW purchase at a 95% load factor for the months of November 2002 through October 2003, excluding April 2003 through June 2003.

8 **WNP-1 Reshape** - Proforma expense is $0 because the contract ended June 2000.

9 **WNP-3** - Proforma cost are based on the expected amount of energy to be received in the proforma period and the midpoint energy rate.

Entitlement & Supplemental Capacity - Proforma expense is reduced because the amount of Entitlement and Supplemental Capacity that the company purchases decreases from 2000 to the proforma period.

Deer Lake-IP&L - Proforma expense is based on a 5-year average.

Small Power - Proforma costs are based on a five-year average for generation and proforma period energy payment rates.

Hydro-Tech - Proforma costs are based on a five-year average for generation and proforma period contract and avoided cost rates.

Wood Power Inc. (WPI) Amortization - Wood Power amortization expense is $0.

Spokane-Upriver - Proforma expense is based on a five-year average for generation and proforma period contract rates.

Potlatch Co-Generation - Proforma expense is $0 because Avista does not have a contract to purchase the output of Potlatch's generation. The Proforma is based on Potlatch generating 50 MW into their own load. 2000 test year loads have been reduced by 50 MW.

Capacity Purchases - Proforma expense is $0 because the inherent capacity costs are incorporated in the energy prices used in the Prosym Model

ESI 4-Year Purchase - Proforma expense is $0 because the contract expired June 30, 2001.

Enron – Backs Cowlitz - Proforma expense is $0 because the contract expired September 30, 2001.

Enron 2 yr - Proforma expense is $0 because the contract expired June 30, 2001.

Sempra 5 yr - Proforma expense is $0 because the contract expires March 31, 2002.

MIECO Purchase - Proforma expense is $0 because the contract expires December 31, 2001.

Rathdrum Turbine Gas Swap – Proforma expense is $0 because the contract expired January 31, 2001.

Black Creek Index Purchase - Proforma expense is based on a 5-year average for generation and the average modeled energy price in August. Puget stores the output of

Black Creek for the year and delivers the power to Avista in August at the Mid-Columbia Index rate less the storage and wheeling costs.

BPA 115 MW Purchase - Proforma expense is $0 because the contract expired September 30, 2001.

Cinergy 3 yr Purchase - Proforma expense is $0 because the contract expired December 31, 2001.

Non-Monetary – Non-monetary accruals include accounting entries related to timing differences to properly match revenues and expenses. The account is adjusted to $0 in the proforma.

PacifiCorp Wind - Proforma expense is $0 because the contract expired September 30, 2001.

Duke Index Purchase - Proforma expense is $0 because the contract expired July 31, 2001.

Idaho Index Purchase - Proforma expense is $0 because the contract expired July 31, 2001.

Total Account 555

Microwave Charge – Proforma expense is $0 because the Company has not recently incurred these expenses.

Metering Amortization Cost – Proforma costs are the amortization expenses for metering installed to provide Dynamic Energy Scheduling (DES) to Cogenetrix and Sovereign. Proforma expense is based on the scheduled amortization of metering expenses.

Total Account 556

Broker Commission Fees – Proforma Costs are based on projected Broker Commission Fees of $2,500 per month.

Hedge Services – Proforma expense is $0 because it is not a reoccurring expense.

Rathdrum Service Fee – Proforma expense is $0 because it is not a reoccurring expense.

38 **Mark to Market Restate** – Proforma expense is $0 because it is not a reoccurring expense.

39 **Clark Contract Buydown** – Proforma expense is $0 because the contract ended July 31, 2001.

40 **PSE Exchange** – Proforma expense is $0 because it is not a reoccurring expense.

41 **Reserves for Uncollectibles** – Proforma expense is $0 because it is not a reoccurring expense.

42 **Rathdrum Gas Storage Optimization Expense** – Proforma expense is $0 because under a new gas storage agreement that began in May 2000 the Company does not buy and sell gas out of storage.

43 Total Account 557

44 **Kettle Falls Wood Fuel Cost** - Proforma fuel expense is an output of the Prosym Model based on the projected unit cost of fuel, the heat content of the fuel and the dispatch of the plant, which determines the volume of fuel consumed.

45 **Kettle Falls Gas** – Proforma expense is $0 because gas was not a fuel option for Kettle Falls in the Prosym Model.

46 **Centralia Coal** – Proforma expense is $0 because the Company sold its share of the plant in May 2000.

47 **Colstrip Coal Cost** - Proforma expense is an output of the Prosym Model based on the projected unit cost of fuel, the heat content of the fuel and the dispatch of the plant, which determines the volume of fuel consumed.

48 **Centralia Oil** - Proforma expense is $0 because the Company sold its share of the plant in May 2000.

49 **Colstrip Oil** – Proforma expense is based on PP&L's (plant operator) estimate of start-up oil expense at Colstrip units 3 and 4 for 2002. Avista's cost is based on its 15% ownership in the plants.

50 Total Account 501

51 **Coyote Springs Gas** - Proforma expense is an output of the Prosym Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

52 **Rathdrum Gas** - Proforma expense is an output of the Prosym Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

53 **Northeast CT Gas** – Proforma expense is an output of the Prosym Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

54 **Boulder Park Gas** – Proforma expense is an output of the Prosym Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

55 **Kettle Falls CT Gas** – Proforma expense is an output of the Prosym Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

56 **Fuel Cell Project Gas** – Proforma expense is $0.

57 **Northeast Oil** – Proforma expense is $0 because oil was not a fuel option for Northeast in the Prosym Model.

58 **Rathdrum Gas Storage Fee** – This expense is for storage of gas that allows for the immediate availability of gas at the Company's gas fuel plants. Proforma expense is based on Avista's contract with Pacific Gas and Electric Company.

59 **Total Account 547**

60 **WNP-3 Transmission** - Proforma WNP-3 wheeling is based on 32.22 MW at a rate of $1.751/kW/mo. Proforma expense increased over the test year because BPA's wheeling rates increased.

61 **CSPE Wheeling** - Proforma expense is based on 8.35 MW for the period July 2002 through March 2003 at a rate of $125/MW/mo. Proforma expense decreased from the test year because the proforma includes only 5 months.

62 **Black Creek Wheeling** - This wheeling expense is for the storage and wheeling of the Black Creek Index Purchase (Account 555). The rate is $6/MWh. Proforma expense decreased from the test year because the amount of energy in the proforma is less than in the test year.

63 **Supplemental Capacity Wheeling** - Proforma expense is based on 7.7935 MW for the period November 2002 through March 2003 at a rate of $1.50/kW/yr. Proforma expense decreased from the test year because the proforma includes only 5 months.

64 **Wheeling for Short-term Purchases and Sales** – Proforma expense is $0.

65 **Garrison/Paul PTP Wheeling** – This wheeling is for the transmission of 196 MW from Colstrip at the Garrison substation and 200 MW from the TransAlta purchase at the Paul substation to Avista's system. Proforma expense is based on 396 MW capacity at a rate of $1.243/kW/mo. Proforma expense increased over the test year because the amount of wheeling purchased increases and BPA's wheeling rates increased.

66 **Townsend Garrison Wheeling** – This expense reflects the transmission of Colstrip power from the Townsend substation to the Garrison substation. Proforma expense is based on 2000 actual expense.

67 **Garrison Burke Wheeling** – Garrison Burke wheeling reflects 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 proforma expense is based on a 5 year average of energy wheeled times the 2000 average transmission rate of $4.62/MWh.

68 **Cogentrix Use of Facilities** - Proforma expense is $0 because the contract ended September 30, 2001.

69 **Clark Service Fee** - Proforma expense is $0 because the contract ended July 31, 2001.

70 **PGE Firm Wheeling** – PGE Firm wheeling reflects the cost of transmission from the John Day substation to COB. Avista has a long-term transmission agreement for 85 MW with Portland General. The Proforma expense is based on 100 MW at 2000 actual expense of $84,780 per month.

71 **Coyote Springs Wheeling** - This wheeling is for the transmission of 140 MW from Coyote Springs II to Avista's system over BPA. Proforma expense is based on 140 MW capacity at a rate of $1.243/kW/mo.

72 **Total Account 565**

73 **Headwater Benefits Expense** - Proforma expense is based on the expense for contract year September 2001 through August 2002.

74 **Rathdrum Lease Payments** - Proforma costs reflect payments per the lease payment schedule.

75 **Rathdrum Municipal Payment** – This includes an annual payment of $50,000 and amortization of a $1 million payment in 1995 to the city of Rathdrum for mitigation related to the Rathdrum generating facility.

76 **Rathdrum Incremental Maintenance** – Proforma expense is $0 because the Company no longer accrues for future maintenance expenses.

77 **FERC Fees** – Included in total FERC fees, Account 928.

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

79 **Short-Term Market Sales** - Short-term sales are normalized through use of the Prosym Model as described in witness Kalich's testimony. The proforma value reflects average short-term sales from the period of record dispatch simulation study.

80 **Puget #2 Sale** - Proforma revenues are lower because the contract amount decreases from 100 MW in 2000 to 33 MW in 2002. Revenue is based on 33 MW capacity at a 75% load factor and a price of $32.11/MWh.

81 **Seattle High Ross** - Proforma revenue is $0 because the contract ended April 30, 2000.

82 **Enron Capacity Sale** – This capacity sale is a result of the monetization of the Portland General capacity sale. Proforma revenue is based on 150 MW at $1/kW/mo.

83 **PGE Monetization Amortization** - Proforma revenue is $0.

84 **Cogentrix 57-Month Sale** - Proforma revenue is $0 because the contract ended September 30, 2001.

85 **PacifiCorp 1994 Sale** - Proforma revenue increased because both the capacity rate and the energy rate increases over the test period. The energy rate is based on the gas cost in the Prosym Model.

86 **EWEB Sale** - Proforma revenue is $0 because the contract ended September 2000.

87 **Clark Sale** – Proforma revenue is $0 because the contract ended July 31, 2001.

88 **Snohomish Sale** – Proforma revenue is $0 because the contract ended September, 2001.

89 **West Kootenay Capacity Sale** – Proforma revenue is $0 because the contract ended February, 2000.

90 **City of Cheney Sale** – Proforma revenue is $0 because the contract ended September 30, 2001.

91 **Pend Oreille Sale** – Proforma revenue is $0 because the contract ended July 31, 2000.

92 **Cowlitz Sale** – Proforma revenue is $0 because the contract ended September 31, 2001.

93 **Nichols Pumping Sale** – This is a sale of energy to other Colstrip Units 3 and 4 owners at the Mid Columbia index price plus $.30/MWh. Proforma revenue is based on 6 MW at the average modeled energy price, with a $.30/MWh adder on 5 of the 6 MW.

94 **Montana Index Sale** – Proforma revenue is $0 because the contract ended July 31, 2001.

95 **Duke Index Sale** – Proforma revenue is $0 because the contract ended July 31, 2001.

96 **Cogentrix DES** – This contract provides load control services to Cogentrix Energy Power Marketing, Inc.

97 **Pend Oreille DES & Spinning Reserves** – This contract provides load control and spinning reserves for Pend Oreille PUD.

98 **Sovereign DES** – This contract provides load control services to Sovereign Power, Inc. Proforma revenue is $0 because the current load being served is near 0 MW and is expected to remain there.

99 **Long-term Prior Period Adjustment** – This debit to revenue reflects an offset to the PGE Service Fee and other true-ups related to sales tied to index purchases. The proforma revenue is $0 because there is no PGE Service Fee revenue or true-ups of index sales in the proforma.

100 **Total Account 447**

101 **Scheduling Services** - Proforma revenue is $0 because the contract ended July 31, 2001.

102 **Skookumchuck Hydro** - Proforma revenue is $0 because there has been no revenue during 2001.

103 **Illinova Exchanges** - Proforma revenue is $0 because the contract ended July 31, 2001.

104 **Cogentrix Use of Facilities** - Proforma revenue is $0 because the contract ended September 30, 2001.

105 **Kaiser Power Management Services** - Proforma revenue is $0 because the contract ended September 30, 2001.

106 **PGE Service Fee** – This revenue is related to the Enron Capacity Sale. This revenue was offset by the Long-term Prior Period Adjustment in 2000. The proforma revenue is $0 because the entire Enron Capacity Sale revenue is included in Account 447.

107 **Puget Storage Fee** – Proforma revenue is $0 because this was a non-reoccurring event.

108 **TECWA Exchange** – Proforma revenue is $0 because this was a non-reoccurring event.

109 **Colstrip Sale of Lots** – Proforma revenue is $0 because this was a non-reoccurring event.

110 **Options Revenue** – Proforma revenue is $0 because no options have been sold in the proforma period.

111 **SCL Exchange** – Proforma revenue is $0 because this was a non-reoccurring event.

112 **Kaiser Transmission Credit** – Proforma revenue is $0 because this was a non-reoccurring event.

113 **Rathdrum Gas Storage Optimization Revenue** – Proforma revenue is $0 because Avista does not purchase and sell gas from storage under the new gas storage arrangement implemented in May 2000.

114 **Total Account 456**

115 **Upstream Storage Revenue** – Proforma revenue is based on the revenue for contract year September 2001 through August 2002.

116 **Colstrip Rents** – Proforma revenue is $0 because this was a non-reoccurring event.

117 **Total Revenue** – Sum of Accounts 447, 456, 453 and 454.

118 **Total Net Expense** – Total expense minus total revenue.

119 **Kettle Falls Tons** – The tons of fuel consumed is calculated by dividing the volume of fuel consumed (in MMBtus) from the Prosym Model by the heat value of the fuel (MMBtus/ton).

120 **Centralia Tons** – There is no fuel consumption at Centralia.

121 **Colstrip Tons** – The tons of fuel consumed is calculated by dividing the volume of fuel consumed (in MMBtus) from the Prosym Model by the heat value of the fuel (MMBtus/ton).

122 **Kettle Falls Cost per Ton** – Proforma cost per ton of $13.77/ton is based on the cost of wood fuel to be delivered during 2002 and 2003.

123 **Centralia Cost per Ton** – There is no coal consumption at Centralia.

124 **Colstrip Cost per Ton** - Proforma cost per ton of $10.47/ton is based on forecasted prices for 2002 and 2003 per the long-term coal supply contract.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-_____

EXHIBIT NO. ____ (WGJ-2)

PROFORMA MONTHLY SHORT-TERM PURCHASES AND SALES AND FUEL EXPENSE

Avista Corp.
Power Supply Proforma
System Numbers - November 2002 through October 2003 Proforma
Short-term Purchases & Sales and Thermal Generation & Fuel Costs

Line No.		Total	720 Nov-02	744 Dec-02	744 Jan-03	672 Feb-03	744 Mar-03	719 Apr-03	744 May-03	720 Jun-03	744 Jul-03	744 Aug-03	720 Sep-03	745 Oct-03
1	Secondary Sales - Dollars	**-$36,066,656**	-$1,674,160	-$2,675,621	-$3,120,729	-$3,310,509	-$2,454,930	-$1,542,501	-$2,405,510	-$5,710,050	-$6,771,486	-$2,858,769	-$2,312,697	-$1,229,695
2	Secondary Sales - MWh	(1,172,193)	-54,269	-86,057	-93,881	-101,534	-86,475	-66,052	-123,233	-207,272	-193,653	-61,833	-59,239	-38,695
4	Average Secondary Sales Price -$/ MWh	$30.77	$30.85	$31.09	$33.24	$32.60	$28.39	$23.35	$19.52	$27.55	$34.97	$46.23	$39.04	$31.78
5	Secondary Purchases - Dollars	**$13,562,746**	$1,295,059	$1,031,797	$710,303	$316,562	$952,732	$1,128,831	$579,604	$245,506	$896,190	$2,834,829	$1,718,059	$1,853,274
6	Secondary Purchase - MWh	370,326	40,218	32,755	16,248	7,152	25,071	35,276	18,697	8,936	19,888	66,180	45,584	54,321
8	Average Secondary Purchase Price - $/MWh	$36.62	$32.20	$31.50	$43.72	$44.26	$38.00	$32.00	$31.00	$27.47	$45.06	$42.84	$37.69	$34.12
9	Net Short-Term Purchases (Sales) MWh	-801,867	-14,051	-53,302	-77,633	-94,382	-61,405	-30,775	-104,536	-198,336	-173,765	4,347	-13,655	15,626
10	Net Short-Term Purchases (Sales) aMW	-92	-20	-72	-104	-140	-83	-43	-141	-275	-234	6	-19	21
11	Average Sales and Purchase Price - $/MWh	$32.17	$31.42	$31.20	$34.79	$33.37	$30.55	$26.36	$21.03	$27.55	$35.91	$44.48	$38.45	$33.14
12	Colstrip MWh	1,637,600	143,547	147,028	147,768	127,444	148,119	143,477	70,289	125,874	143,126	148,666	143,856	148,405
13	Conversion Factor, MWh/ton		1.453	1.453	1.453	1.453	1.453	1.453	1.453	1.453	1.453	1.453	1.453	1.453
14	Colstrip Tons	1,127,179	98,805	101,201	101,710	87,721	101,952	98,757	48,381	86,641	98,515	102,328	99,018	102,149
15	Cost/Ton	$10.47	$10.47	$10.47	$10.47	$10.47	$10.47	$10.47	$10.47	$10.47	$10.47	$10.47	$10.47	$10.47
16	Colstrip Fuel Cost	**$11,803,835**	$1,034,689	$1,059,777	$1,065,114	$918,620	$1,067,646	$1,034,187	$506,642	$907,302	$1,031,655	$1,071,585	$1,036,915	$1,069,705
17	Kettle Falls MWh	172,928	11,020	17,313	19,005	17,908	11,007	6,707	2,254	8,246	20,462	21,100	21,246	16,660
18	Conversion Factor, MWh/ton		0.618	0.615	0.618	0.615	0.618	0.614	0.608	0.607	0.611	0.618	0.618	0.618
19	Kettle Falls Tons	280,857	17,834	28,129	30,759	29,113	17,801	10,928	3,708	13,575	33,508	34,165	34,376	26,961
20	Cost/Ton	$13.77	$13.77	$13.77	$13.77	$13.77	$13.77	$13.77	$13.77	$13.77	$13.77	$13.77	$13.77	$13.77
21	Kettle Falls Fuel Cost	**$3,868,595**	$245,651	$387,453	$423,679	$401,007	$245,196	$150,531	$51,072	$186,982	$461,550	$470,601	$473,501	$371,370
22	Coyote Springs MWh	766,131	70,695	68,922	82,201	69,792	76,631	48,112	18,532	36,306	72,458	75,227	75,810	71,445
23	Dispatched Gas Cost, $/dth	$3.52	$3.34	$3.58	$3.64	$3.58	$3.47	$3.50	$3.59	$3.52	$3.40	$3.42	$3.41	$3.49
24	Coyote Springs Fuel Cost	**$19,213,145**	$1,699,013	$1,768,407	$2,153,417	$1,795,254	$1,900,516	$1,202,983	$475,064	$916,545	$1,776,247	$1,860,281	$1,870,811	$1,794,608
25	Boulder Park MWh	66,484	5,356	3,930	6,960	6,052	4,196	1,091	1,770	2,879	8,587	9,375	10,028	6,260
26	Dispatched Gas Cost, $/dth	$3.75	$3.65	$3.97	$4.00	$3.93	$4.02	$4.27	$4.09	$3.64	$3.59	$3.57	$3.55	$3.73
27	Boulder Park Fuel Cost	**$2,262,208**	$177,353	$141,415	$252,347	$215,574	$153,085	$42,314	$65,750	$95,170	$280,140	$303,976	$323,069	$212,015
28	Kettle Falls CT MWh	15,214	977	985	1,780	1,544	928	500	156	544	1,935	2,205	2,314	1,347
29	Dispatched Gas Cost, $/dth	$3.81	$3.84	$4.05	$4.00	$3.92	$4.12	$4.04	$4.24	$3.75	$3.65	$3.60	$3.61	$3.87
30	Kettle Falls CT Fuel Cost	**$507,776**	$32,860	$34,857	$62,224	$52,903	$33,472	$17,670	$5,806	$17,860	$61,863	$69,509	$73,167	$45,586
31	Rathdrum MWh	157,705	7,586	2,864	11,622	11,768	1,612	0	1,096	12,760	28,463	34,887	33,959	11,087
32	Rathdrum Fuel Cost	$3.84	$4.09	$4.47	$4.42	$4.31	$4.31		$4.29	$3.61	$3.74	$3.56	$3.67	$4.18
33	Rathdrum Fuel Cost	**$7,232,285**	$370,588	$152,800	$614,206	$606,433	$82,969	$0	$56,200	$551,221	$1,271,045	$1,485,247	$1,487,742	$553,834
34	Northeast MWh	24,900	655	82	1,438	57	105	0	0	1,937	4,149	9,093	6,385	998
35	Northeast Fuel Cost	$3.82	$4.24	$4.52	$4.67	$4.56	$4.43			$3.97	$3.98	$3.47	$3.81	$4.41
36	Northeast Fuel Cost	**$1,236,465**	$36,166	$4,826	$87,376	$3,390	$6,076	$0	$0	$100,071	$214,778	$410,313	$316,285	$57,184
37	Total Fuel Expense	**$46,124,309**	$3,596,320	$3,549,535	$4,658,362	$3,993,180	$3,488,960	$2,447,684	$1,160,533	$2,775,151	$5,097,278	$5,671,513	$5,581,489	$4,104,301
38	Net Fuel and Purchase Expense	**$23,620,398**												

Exhibit No. ___ (WGJ-2)
Docket No. UE-_____
Johnson, Avista

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-_____

EXHIBIT NO. ____ (WGJ-3)

TEMPORARY DEFERRAL ACCOUNTING MECHANISM

Avista Corp.
Estimated Power Cost Deferrals (Jan 02 - Oct 02), Power Cost Adjustment Entries (Nov 02 - Dec 02)
2002

Line No.			744	672	744	719	744	720	744	744	720	745	720	744
	ACTUAL EXPENSE	Total	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
1	555 Purchased Power	$75,194,950	$10,206,650	$9,157,450	$7,405,750	$3,142,600	$1,575,300	$1,992,900	$5,370,000	$5,273,900	$6,017,000	$8,580,200	$7,785,100	$8,688,100
2	501 Thermal Fuel	$17,977,048	$1,672,662	$1,554,871	$1,338,157	$1,352,797	$975,545	$1,591,981	$1,752,909	$1,788,283	$1,456,716	$1,422,293	$1,522,659	$1,548,175
3	547 CT Fuel	$50,031,732	$4,660,996	$40,000	$40,000	$40,000	$40,000	$4,122,247	$8,531,110	$11,285,441	$8,312,040	$4,346,364	$4,224,144	$4,389,390
4	447 Sale for Resale	$61,644,900	$4,292,200	$3,739,500	$4,496,700	$1,581,700	$4,758,300	$9,568,600	$11,923,600	$9,247,900	$3,890,400	$1,748,700	$2,742,700	$3,654,600
5	Total Actual Expense	$81,558,830	$12,248,108	$7,012,821	$4,287,207	$2,953,697	-$2,167,455	-$1,861,472	$3,730,419	$9,099,724	$11,895,356	$12,600,157	$10,789,203	$10,971,065
6	Potlatch Direct Assignment Credit	-$7,121,880	-$604,872	-$546,336	-$604,872	-$584,547	-$604,872	-$585,360	-$604,872	-$604,872	-$585,360	-$605,685	-$585,360	-$604,872
7	Total Adjusted Actual Expense	$74,436,950	$11,643,236	$6,466,485	$3,682,335	$2,369,150	-$2,772,327	-$2,446,832	$3,125,547	$8,494,852	$11,309,996	$11,994,472	$10,203,843	$10,366,193
	AUTHORIZED EXPENSE	Total	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
8	555 Purchased Power	$176,393,067	$19,750,869	$17,715,941	$17,965,489	$13,827,544	$9,429,128	$10,780,817	$17,338,742	$17,318,558	$17,633,633	$18,240,957	$8,216,171	$8,175,218
9	501 Thermal Fuel	$13,743,630	$1,386,686	$1,114,117	$1,207,061	$1,024,078	$844,373	$375,989	$971,393	$1,380,273	$1,313,820	$1,382,270	$1,288,340	$1,455,230
10	547 CT Fuel	$8,872,279	$907,791	$78,189	$77,136	$78,350	$77,136	$78,285	$77,137	$120,669	$1,202,634	$1,676,667	$2,355,980	$2,142,305
11	447 Sale for Resale	$112,575,184	$10,772,670	$10,053,092	$10,900,890	$9,940,681	$9,590,789	$9,929,529	$11,987,748	$11,346,460	$11,268,891	$10,634,016	$2,563,057	$3,587,361
12	Authorized Expense	$86,433,792	$11,272,676	$8,855,155	$8,348,796	$4,989,291	$759,848	$1,305,562	$6,399,524	$7,473,040	$8,881,196	$10,665,878	$9,297,434	$8,185,392
13	Water Stipulation Adjustment	-$2,639,215	-$323,769	-$372,513	-$245,470	-$148,937	-$96,059	-$124,198	-$519,620	-$204,468	-$350,812	-$253,369		
14	Colstrip EAF Adjustment	-$337,287	-$40,120	-$27,032	-$38,642	-$24,195	-$27,733	-$9,530	-$23,936	-$38,721	-$49,673	-$57,705		
15	Adjusted Authorized Expense	$83,457,290	$10,908,787	$8,455,610	$8,064,684	$4,816,159	$636,056	$1,171,834	$5,855,968	$7,229,851	$8,480,711	$10,354,804	$9,297,434	$8,185,392
	CHANGE IN TOTAL NET EXPENSE													
16	Actual - Authorized Power Supply Expense	-$9,020,340	$734,449	-$1,989,125	-$4,382,349	-$2,447,009	-$3,408,383	-$3,618,666	-$2,730,421	$1,265,001	$2,829,285	$1,639,668	$906,409	$2,180,801
17	Fuel Expense not included in Account 547	$15,472,832	$0	$1,902,564	$2,360,610	$2,188,461	$2,249,010	$1,823,158	$0	$0	$0	$1,787,936	$1,605,815	$1,555,278
18	Coyote Springs Capital, O&M	$7,133,385						$1,426,677	$1,426,677	$1,426,677	$1,426,677	$1,426,677		
19	Boulder Park Capital, O&M	$3,932,000	$393,200	$393,200	$393,200	$393,200	$393,200	$393,200	$393,200	$393,200	$393,200	$393,200		
20	Bi-Fuel Lease, O&M	$4,814,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$146,000	$3,500,000		
21	Kettle Falls CT Capital, O&M	$518,980							$129,745	$129,745	$129,745	$129,745		
22	Total Net Expense - System	$22,850,857	$1,273,649	$452,639	-$1,482,539	$280,652	-$620,173	$170,369	-$634,799	$3,360,623	$4,924,907	$8,877,226	$2,512,224	$3,736,079
23	Washington Allocation	$15,264,050	$853,217	$303,223	-$993,153	$188,009	-$415,454	$114,130	-$425,252	$2,251,281	$3,299,195	$5,946,854	$1,665,353	$2,476,647
24	Washington Retail Revenue Adjustment	$11,013,905	$601,788	-$221,425	$1,385,886	$1,451,127	$1,830,506	$2,299,264	$1,700,967	$465,285	$469,430	$574,750	$420,809	$35,518
25	Change in Total Net Expense	$26,277,955	$1,455,005	$81,798	$392,733	$1,639,136	$1,415,052	$2,413,394	$1,275,715	$2,716,566	$3,768,625	$6,521,604	$2,086,162	$2,512,165
26	90% of Change in Total Net Expense	**$23,650,162** Surcharge	$1,309,505 Surcharge	$73,618 Surcharge	$353,460 Surcharge	$1,475,222 Surcharge	$1,273,547 Surcharge	$2,172,055 Surcharge	$1,148,144 Surcharge	$2,444,909 Surcharge	$3,391,763 Surcharge	$5,869,444 Surcharge	$1,877,546 Surcharge	$2,260,949 Surcharge
27	90% of Change in Total Net Expense (Jan-Oct) Temporary Power Cost Deferral	**$19,511,667** Surcharge												

Exhibit No. _____ (WGJ-3)
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Johnson, Avista
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