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 the revenue is recorded in Account 446. Account 557 minus Account 456 is what would be included in the deferral calculation.

Exhibit _______ (WGJ-3) shows the methodology for the proposed temporary power deferral accounting mechanism. The estimated deferrals for January 2002 through October 2002 period total $19,511,667 in the surcharge direction.

## V. Proposed Power Cost Adjustment Mechanism

**Overview**

Q. Would you describe Avista's proposed power cost adjustment methodology?

A. Yes. The Company is proposing to use a PCA calculation methodology based on a comparison of actual and authorized levels of power supply expense netted against the change in retail revenue. 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. The methodology would also include fuel expenses not included in FERC account 547 and would include a retail revenue adjustment to account for the revenue offset to the power supply costs. The PCA entries, however, would not include the costs or benefits of new resources until the Commission has reviewed them.

The monthly power cost adjustment entries would accumulate in a balancing account. When the balance in the account reaches the trigger, as explained by Mr. McKenzie, the Company would petition the Commission for a rate adjustment, either a rebate or surcharge depending on the direction of the balancing account.

**PCA Calculations**

Q. How would the power cost adjustment be calculated each month?

A. PCA entries would be calculated by subtracting authorized net power supply expense from actual net power supply expense to determine the change in power 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.

10 **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.

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

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

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

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

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

16 **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.

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

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

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

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

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

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

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

24 **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.

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

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

27 **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.

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

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

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

31 **Total Account 555**

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

33 **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.

34 **Total Account 556**

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

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

37 **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 | Nov-02 | Dec-02 | Jan-03 | Feb-03 | Mar-03 | Apr-03 | May-03 | Jun-03 | Jul-03 | Aug-03 | Sep-03 | Oct-03 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 720 | 744 | 744 | 672 | 744 | 719 | 744 | 720 | 744 | 744 | 720 | 745 |
| 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. | | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **ACTUAL EXPENSE** | | 744 | 672 | 744 | 719 | 744 | 720 | 744 | 744 | 720 | 745 | 720 | 744 |
| 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)
Docket No. UE-_________
Johnson, Avista