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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO.	)	**CASE NO. AVU-E-04-1/ AVU-G-04-1**

DIRECT TESTIMONY OF KEITH HESSING

IDAHO PUBLIC UTILITIES COMMISSION

JUNE 21, 2004

Q. Please state your name and business address for the record.

A. My name is Keith D. Hessing and my business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission as a Public Utilities Engineer.

Q. What is your educational and experience background?

A. I am a Registered Professional Engineer in the State of Idaho. I received a Bachelor of Science Degree in Civil Engineering from the University of Idaho in 1974. Since then, I worked six years for the Idaho Department of Water Resources, and two years for Morrison-Knudsen. I have been continuously employed at the Commission since August 1983.

As a member of the Commission Staff, my primary areas of responsibility have been electric utility power supply, revenue allocation and rate design.

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

A. My testimony discusses electric issues including Jurisdictional Separations, Class Cost of Service and PCA issues including Deal "A" and Deal "B" gas purchase issues carried into this case from Case No. AVU-E-03-6 by Commission Order No. 29377. I also propose a change in PCA methodology. My testimony concludes with a brief discussion of average rate changes for each customer class and an exhibit showing the overall effects of Staff's rate proposal.

Q. Please summarize your testimony.

A. I recommend that the Commission accept the Jurisdictional Separation study proposed by the Company. I also recommend that the Class Cost of Service methodology proposed by Avista be accepted by the Commission. I provide Cost of Service results, that include Staff's accounting adjustments, to Staff witness Schunke which he uses as the starting point in allocating revenue requirement to the various customer classes.

I recommend that the Commission accept the Company's calculation of base power supply costs for use in future PCA calculations. I recommend that losses on the purchase and subsequent sale of Deal "B" gas in the amount of $6,496,669 not be charged to customers. I also propose a reduction in PCA rates.

I propose that the PCA rate design methodology be changed once the current deferral balance is eliminated. Currently increases and decreases are spread to customer classes based on each class's percentage of total revenue and recovered in the energy charge for each class. I propose that PCA increases and decreases be surcharged or rebated to customers on the basis of energy consumption. My proposal would apply an equal cents per kWh rate to all customer classes except lighting classes which would receive the average percentage increase or decrease.

My testimony concludes with an exhibit showing the combined average revenue changes for each customer class caused by Staff's base rate proposal, DSM Rider rate proposal and PCA rate change proposal. The overall net electric increase proposed by Staff is 2.4%.

JURISDICTIONAL SEPARATIONS AND CLASS COST OF SERVICE

Q. What Jurisdictional Separation and Class Cost of Service methodology is used by the Company?

A. The Company applied the same Jurisdictional Separation methodology accepted by the Commission in its last general rate case, Case No. WWP-E-98-11. The methodology directly assigns revenues, costs and investment to jurisdictions where appropriate and allocates the remaining amounts. The methodology uses 2002 test year booked amounts without adjustment. All adjustments are included on an Idaho System basis at the beginning of the Cost of Service process.

The Company used the same Peak Credit Cost of Service methodology that it used in its last general rate case with minor modifications. The Commission accepted that methodology as the starting point for revenue allocation in that case. Staff proposes only an incremental move toward full cost of service in recognition of the fact that cost of service results are not precise and unacceptably large increases to some classes would occur. Staff witness Schunke discusses revenue allocation to the various customer classes in his testimony.

Q. Is there value in applying consistent Jurisdictional Separation and Class Cost of Service methodology from case to case?

A. Yes, there is. It allows the usage and customer characteristics that form the allocators and the accounting data to drive the results. There are substantial changes caused by these factors without changing the methodology.

Q. Does the Staff accept the methodology and allocation factors used by the Company in its filing?

A. Yes.

Q. Have you prepared an exhibit that shows the Class Cost of Service results that have been used as the starting point for revenue allocation in Staff's case?

A. Yes, I have. Staff Exhibit No. 138 shows

Class Cost of Service results based on a total revenue requirement of $169,326,876 which is a $23,078,876, 15.78% increase above existing base rates. This information was provided to Staff witness Schunke for revenue allocation purposes.

PCA ISSUES

Deal "A" and Deal "B"

Q. Please summarize the Deal "A" and Deal "B" issue carried into this case by Commission Order No. 29377 from Case No. AVU-E-03-6, which was the Company's last PCA case.

A. In March 2001, Avista Utilities purchased gas at index to operate its gas-fired resources for the purpose of producing electricity. Deal "A" deliveries were for 27,658 dth/day for a 36-month period beginning November 1, 2001. Deal "B" deliveries were 20,000 dth/day for a 17-month period beginning June 1, 2002. Total Deal "A" and Deal "B" purchases were exactly the quantity of gas required to run the Coyote Springs 2 CCCT at its full generating capacity of 280 MW.

In April and May of 2001, using 4 separate transactions, the Company fixed the price, using hedges, for 40,000 dth/day, which is 84 percent of the gas. The hedged price averaged approximately $6.00 per decatherm. The other 16 percent of the gas remained at index. The

Company's Confidential Exhibit 7, Schedule 16, summarizes the Deal "A" and "B" transactions.

When the various gas price hedges were established, electric forward market prices were high and if the electric prices would have persisted in real time a number of good things could have happened to the Company and its customers using the fixed price gas. I discuss those later in this testimony. However, between the time that the price was fixed and the time the gas supplies were to be delivered, electric and gas market prices dropped precipitously. After this happened, the best plan for the Company and its customers was to sell the gas at a loss and purchase the Company's electric needs from the wholesale electric market each month. The Company had losses on Deal "A" and Deal "B" which it proposed to include in the PCA. The PCA would have passed 90% of the losses for the Idaho jurisdiction on to customers while the Company's shareholders would have been responsible for the other 10%. In its comments in the referenced case, Staff proposed that only Deal "B" losses be excluded from PCA treatment and recovery from ratepayers. In its final order in that case, the Commission did not rule on the issue but required that both Deal "A" and Deal "B" losses be examined in more detail in this proceeding. Staff Exhibit No. 139 is a copy of the Staff Comments filed in Case No. AVU-E-03-6. The detailed discussion of Deal "A" and "B" begins on page 6. An understanding of the referenced comments and testimony is essential to full understanding of the Deal "A" and "B" issues in this case.

Q. Please summarize Staff's conclusions in that case.

A. With regard to the Company's Energy Resources Risk Policy, the Staff concluded that Deal "B" purchases violated risk policy provisions. Also, Deal "B" price hedges were entered into with Avista Energy (AE), an unregulated affiliate of the regulated utility. Staff concluded that appropriate safeguards were not in place or followed to protect customers when the regulated utility does business with its affiliate. Safeguards could include a proper Code of Conduct or a requirement for lower-of-cost or market pricing. The Staff also concluded that the Company took unusual risks when hedging the price for the length of these gas purchase deals for its electric customers. Similar risks were not taken for its natural gas customers.

Q. What has changed with regard to Deal "A" and "B" purchases since the Staff filed its comments in the last PCA case?

A. Several months have passed and the time frame for gas delivery under Deal "B" is over. It ended at the end of October 2003. In the last few months of the deal, Avista sold some of the gas at a loss but burned some of the Deal "B" gas profitably.

Q. Has Staff's position changed since its PCA filing?

A. No, but Staff does recognize that some Deal "B" gas has since been burned profitably. It is only fair that the savings on the price of the gas when the market is above $6.00 be netted against losses when the market is below $6.00. Staff's position in this case is that the net of Deal "B" profits and losses, net losses, should not be included in the PCA.

Q. Does the Company's filing in this case address the concerns that Staff raised in its filed comments in Case No. AVU-E-03-6?

A. Only partially. In his testimony, Company witness Lafferty presents and discusses Deal "A" and Deal "B" purchases from a longer-term, resource planning, point of view instead of the near term, risk policy, point of view presented by Staff in its previously referenced PCA comments.

Q. Please discuss some of the differences in the two approaches.

A. The risk policy perspective views resource decisions for the coming 18-month period. This process initially assumes normal load and resource conditions and updates both based on forecasts as they become available. Forecasts become more accurate as they near real time. The policy includes written rules and maximum long and short position limits that vary based on the period of time remaining before energy is needed, real time. In general the Company's "position" is the difference between expected loads and expected resources.

The long-term planning view presumably guides resource decisions that are made for periods further than 18 months out. It assumes critical water conditions resulting in approximately 150 average MW's less available generation than under normal water conditions. Eighteen months out from real time, where the planning criteria time period and operating criteria time period meet, loads and resources that are perfectly balanced based on the long-term critical water planning criteria result in an approximate 150 MW long position under the risk policy review criteria because the risk policy is based on normal water condition assumptions. Eighteen months out, the long limit allowed in the risk management plan is 150 MW above normal water conditions. Therefore, the Company would move into the risk policy analysis period with the largest amount of extra resources that the plan allows. Of course, if the Company is just a little long based on long-term critical water planning criteria, it transitions into the risk policy period above the established limits and would immediately have to sell energy to get below the long limit contained in the Company's Risk Policy.

Q. Does Company witness Lafferty suggest that there are concerns, other than critical water, that the Company should be allowed to consider when it purchases fuel for its gas fired resources?

A. Yes. In addition to water conditions Mr. Lafferty suggests that loads and outages should also be considered. He states that actual loads could be higher than expected by 87 MW and that a unit outage at Colstrip could reduce generating capability by 100 MW. (Pg. 43)

Q. Does it make sense to purchase energy or fixed price fuel to produce energy for 300+ MW of unusual deficiencies?

A. No, not before the deficiencies become known. The chances of all three events occurring together are extremely improbable.

Q. Is it reasonable to have some energy reserve to address these types of deficiency causing events if they do occur?

A. Yes, it is. The Company's risk policy very specifically provides for this by establishing a long limit of 150 MW. The Company's Risk Policy says, "Reasons to maintain long positions may include strategies to mitigate potential negative impacts of unplanned loss of resources, adverse changes in hydro conditions, or adverse impacts of load variations as compared to the forecast". (Exhibit 139, Energy Resources Risk Policy, Attachment J, Pgs. 3 and 4 of 15)

Q. Do the differing perspectives concerning appropriate review criteria cause the Company and Staff to reach different conclusions?

A. I think so. The long-term perspective used by the Company to justify these transactions is very different than the Company's near term risk policy perspective used by the Staff.

Q. How are the Deal "A" and "B" purchases initially positioned relative to the 18-month transition point between the long-term and short-term analytical approaches?

A. As indicated in Staff comments in the last PCA case, both purchases were ongoing at the 18-month transition point which was about October 2002.

Q. Why does Staff utilize the Company's shorter-term risk policy method of analysis to evaluate the merits of the gas transactions?

A. The Energy Resources Risk Policy is written and well defined. It is designed to address the very situations that the Company says could occur. The Resource planning process that Staff is familiar with, the Integrated Resource Planning (IRP) process, does not include criteria for acquiring energy or gas to produce energy which is the issue being addressed here.

Q. Was the Company using a long-term planning process like the one discussed in its testimony and used to justify its long out-of-limit position before the Deal "A" and "B" gas purchases?

A. No. If the Company was using it's long term resource acquisition plan, its resource positions would have been long, probably even long out of limits in its Position Reports. As shown on the Company's Position Limit Chart for March 7, 2001 (Exhibit No. 139, Confidential Attachment K, pg. 1), the load resource balance is short coming into the 18 month planning period and remains short or minimally long, 35 MW maximum, for the entire period. This report reflects the Company's position just prior to Deal "A" and "B" transactions. This is not consistent with the long-term acquisition process the Company says it uses.

Q. In Staff's previously mentioned PCA comments, Staff pointed out that Avista's gas operations did not make the same kind of long-term purchases for its gas customers in early 2001. What information do you have that supports this position?

A. Staff Exhibit No. 140 was provided by the Company in response to Staff Production Request No. 27. The Exhibit shows that in early 2001 the Company did not purchase gas two and three years into the future for its gas customers. The fact that the Company failed to purchase gas with the same kind of long-term deals for its gas customers that it did for its electric customers demonstrates the Company's inconsistency. If long-term gas purchases were expected to be beneficial to the electric utility, why would they have not been expected to be beneficial to the gas utility? Staff Exhibit No. 140 shows that in the same time frame, the Company rarely purchased gas for its gas customers at Deal "A" or "B" prices and never made fixed price purchases for use more than two years in the future.

Q. In its PCA comments the Staff discussed the hedge transactions between Avista Utilities and Avista Energy (AE) that fixed the gas cost for Deal "B" in April and May of 2001. Do you have anything further to add to that discussion?

A. Yes. When the gas cost was fixed with Avista Energy, both AE and the utility along with its customers were exposed to risk. AE's risk was that gas prices would go up and that when it needed gas for delivery it would be more costly.

The utility was exposed to several types of risk. It had the risk that gas prices would go down and gas would cost less when it was needed. The utility also had the risk that electric and gas prices would go down such that the gas could not be economically used to produce electricity and the gas would have to be sold at a loss. Of course, through the PCA 90% of any loss would be recovered from customers. This created a situation where one affiliate essentially bet against the other affiliate. One was going to profit and one was going to pay and because of the PCA, Avista shareholders were substantially protected from paying. Because the deal with AE was not provided to Avista Utilities at cost, AE had the opportunity to profit by keeping the difference between the actual cost and fixed price of gas sold to the regulated utility. In fact a counter party such as AE would not have made the deal if it did not expect to profit. In the end, AE profited and the regulated utility is proposing that its customers pay 90% of the costs. If AE chose not to hedge its risks on the transactions, it profited by the difference between actual and fixed price. In the end regulated utility shareholders paid 10% of the AE profit and utility ratepayers paid the other 90% of AE's profit. It is Staff's position that whether AE profited or not, Deal "B" was not at the lower-of-cost or market and, therefore, constituted an inappropriate affiliate transaction. Staff's Deal "B" proposal in this case, that net losses on the gas sales should not be allowed in the PCA, amounts to giving the customer the better deal, cost or market.

Q. Why does Staff propose to disallow Deal "B" loss recovery and accept Deal "A" loss recovery?

A. Deal "A" hedges were not done with an Avista affiliate, but Deal "B" hedges were. Also, the Deal "A" gas purchase did not put the Company over the long limit contained in it's Risk Policy, the Deal "B" purchase which was executed at a later point in time caused the utility to exceed the long limit. Not only did the transaction place Avista above the long limit, but Avista's position continued to stay above the limit.

Q. Has the information provided by the Company changed Staff's position regarding disallowance of Deal "B" net losses from PCA treatment?

A. No. It remains Staff's position that net losses on the sale of Deal "B" gas should not be included in the PCA.

Q. What is the basis for this conclusion?

A. It is Staff's position that the Company violated both the intent and the written requirements of its own Energy Resources Risk Policy. The Company purchased gas for electric generation that exceeded the limits allowed by the policy, then fixed the price which created a speculative position that led to the losses. Also in executing the Deal "B" price hedges with its unregulated affiliate, Avista Energy, the Company created a potential conflict of interest. In order to avoid potential abuse or even the appearance of abuse, the Company needs to provide its customers with the best deal by recording the transaction at the lower-of-cost or market absent other specific rules established to protect customers. Staff believes that it was extremely risky to lock the price of gas at a traditionally high price in a gas market with prices falling even though forward electric prices were high.

Q. What other reasons could have caused the Company to take the risks that it took in the Deal "A" and "B" purchases?

A. Avista needed the Coyote Springs 2 plant to reduce its dependence on what had become a highly volatile energy market. Coyote Springs 2 was to be one of the most efficient combined cycle gas-fired combustion turbines in the region with a 7,000 BTU/kWh heat rate. Avista was financially stressed and needed to obtain a gas supply in order to secure financing for the project. Deal "A" provided the necessary gas transportation along with gas supply. If electric prices held at or near the forward level at the time of the Deal "A" and "B" hedges, the operation of CS 2 would have been profitable. Power needed by customers could be generated at a cost below the market price. If the Company was long on supply, it could generate power and sell the power for profit. Ten percent of the profit would go to shareholders, while 90 percent of the profit would go to the PCA to buy down PCA balances and reduce customer rates.

This philosophy could have worked if the electric sale of the long energy had also been made at the same time to lock in the gain and reduce the long position. Absent such an electric power sale, the transaction was purely speculation.

Also, if all had gone according to the Company's plan, Coyote Springs 2 would have been demonstrated to be used and useful and therefore, easily rate based.

Q. The Company fixed the gas prices for 84% of the Deal "A" and "B" gas. Could Avista have fixed electric forward prices as well?

A. Yes, but the cost may have been substantial and may have reduced or eliminated the expected profits.

Q. If the cost of fixing the electric forward prices was high or prohibitive, what would this tell Avista about the risk of the transaction?

A. If the parties who sell this type of financial instrument wanted a high premium to fix the forward price of electricity they obviously believed that there was a great deal of risk in selling forward at a fixed price. If there is a great deal of risk that forward electric prices would be lower than forecast, the Company should have chosen shorter term less risky deals that would have captured the benefits of layering or dollar cost averaging. Again as previously stated, absent electric sale transactions this activity was based on speculation. Customers should not pay for Avista to speculate.

Q. In two different places in his testimony, Company witness Lafferty characterizes Staff's proposal that electric forward prices could have been hedged along with gas prices as "retrospective" (pg. 47) or "after the fact" (pg. 51) views. Would you please comment.

A. It is a common practice in the energy business to capture the benefits of a deal by locking in all prices. It requires no hindsight to see the advantages of so doing in the Deal "A" and "B" transactions. By not locking the electric forward prices in these transactions the Company gambled that electric prices would not decline substantially. The Company lost on that gamble. As stated previously, customers should not pay for speculation or a gamble.

Q. What amount does Staff recommend be removed from the PCA deferral account to reflect Deal "B" losses?

A. Deal "B" losses are calculated on Staff Confidential Exhibit No. 141. The bottom line shows that 90% of Idaho jurisdictional losses on Deal "B" that have been deferred for recovery are $6,496,669. This is the amount that Staff recommends be removed from the PCA deferral account.

Q. Does Staff Exhibit No. 141 also show the Deal "A" losses that Staff is not proposing to remove from PCA treatment?

A. Yes. Ninety percent of the Idaho jurisdictional share of Deal "A" losses are shown to be $8,677,766.

Updated PCA Components

Q. Are base PCA net power supply costs to be updated as a result of this general rate case?

A. Yes. Staff proposes that base power supply costs be updated as a result of this case. The Company proposed the same. Company witness Johnson shows the new base amounts on Exhibit 10, Schedule 4.

Q. What are base power supply costs used for in the PCA?

A. The PCA calculates the difference between actual and authorized base Idaho jurisdictional power supply costs and, after appropriate sharing and a load change revenue adjustment, defers the difference for later recovery or rebate.

Q. Does Staff support the base amounts proposed by the Company as shown in Company witness Johnson's Exhibit 10, Schedule 4?

A. Yes.

Q. Is there another PCA component that the Company proposes to update in this case?

A. Yes. In his testimony, Company witness Johnson proposes to update the load change revenue adjustment multiplier.

Q. What change is proposed in the multiplier?

A. The Company proposes that the multiplier be changed from 21.23 $/MWh to 36.38 $/MWh.

Q. How is the multiplier used?

A. The multiplier is the average annual variable power supply cost of meeting new load as determined from the Company's power supply model. It is multiplied times the difference between base and actual loads to determine the cost of load changes that occur and accrue in the PCA. The resulting cost is used to adjust the power supply cost deferral for changes in power supply costs associated with load growth or decline. By removing this resulting amount from the PCA calculation, power supply costs associated with load change are reserved for consideration in general rate cases.

Q. Does Staff agree with the Company's calculation of the load change revenue adjustment multiplier.

A. Yes.

PCA Rate Reduction

Q. Does the Company recommend a reduction in current PCA rates?

A. Yes. In its filing the Company estimated a deferral balance of approximately $23 million at the end of September 2004. The Company proposes to implement reduced PCA rates in this case designed to recover $11.5 million of the estimated balance each year for two years.

Q. What is Staff's PCA rate proposal?

A. Staff proposes to reduce the Company's actual end of May 2004 balance of $26,261,334 by $6,496,669 in Deal "B" losses and calculate rates to recover the remaining balance over 2 years. This reduces the PCA revenue requirement by $17,963,835 per year. Staff believes it is more appropriate to use actual amounts than estimates even though the PCA trues the amounts up to actual.

Other PCA Matters

Q. Does Staff propose a change in the PCA mechanism?

A. Yes. Staff proposes to change the way rates are calculated in the PCA mechanism once the current PCA deferral balance is eliminated. The current PCA mechanism assigns class revenue responsibility based on a uniform percentage of revenue spread to each class and then assigns recovery to the energy portion of the rate within each class. Staff proposes that PCA costs be recovered from Avista ratepayers on a uniform cents per kWh basis. The PCA rate would be the same for all schedules except lighting schedules. Lighting schedules would pay/receive the Idaho average increase/decrease.

Q. Why should this change be made?

A. The allocation of PCA costs to individual rate classes based on a percentage of total revenue assumes and relies on a mix of fixed and variable costs like those allocated to each customer class through the Cost of Service process. Above or below normal power supply costs that are captured in the PCA mechanism are directly related to the variable costs of providing energy. The fixed costs of power supply are not captured in the PCA. Therefore, it is more appropriate to recover variable power supply costs with an equal cents per kWh charge that applies to all energy use.

Q. When does Staff propose this change be made?

A. Staff proposes that this change be made when the current deferral balance is eliminated.

Q. Why not make the change with the new rates that will result from this case?

A. As pointed out by the Company in this case there is a very substantial PCA deferral balance that has accumulated and that will be recovered from customers in the next few years. Staff believes that because the balance was accumulated under the current methodology it is fair to recover this balance under the current methodology. However, when the balance is eliminated, the methodology should be changed. The proposed methodology causes high load factor customers, such as Potlatch and others, to pay/receive a larger percentage of surcharges/rebates. To impose such a change when there is a large balance to surcharge would initially penalize high load factor customers. It is only fair to make the change when the current balance is at or near zero and, going forward, there is an equal probability of credit or surcharge.

FINAL REVENUE ALLOCATION

Q. What rates does Staff propose to change as the result of this case?

A. Staff proposes that base rates change based on the revenue requirement spread included in Staff witness Schunke's testimony. His testimony also provides Staff's proposed base rates. In addition, Staff witness Anderson proposes a change in DSM Rider rates. Finally, my testimony recommends changes to PCA rates. I propose that these PCA rate changes stay in place until October 2005 when an annual review of the deferral balance could cause them to change. Staff Exhibit No. 142 shows all of the revenue requirement changes by customer class and the resulting net percentage increases and decreases measured from existing rates. As shown on the exhibit, the overall change is a 2.4% increase above existing rates.

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

A. Yes, it does.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 21ST DAY OF JUNE 2004, SERVED THE FOREGOING **DIRECT TESTIMONY OF KEITH HESSING,** IN CASE NO. AVU-E-04-1/AVU-G-04-1, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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IDAHO PUBLIC
UTILITIES COMMISSION

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IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO.	**CASE NO. AVU-E-04-1/ AVU-G-04-1**

EXHIBITS OF KEITH HESSING

IDAHO PUBLIC UTILITIES COMMISSION

JUNE 21, 2004

ALLEGEDLY PROPRIETARY DATA HAS BEEN DELETED FROM THESE EXHIBITS

Electric Utility
Scenario: Staff Case
Last Idaho Method modified
Common Costs by 4-Factor

AVISTA UTILITIES
Cost of Service Summary
For The Twelve Months Ended December 31, 2002

Idaho Jurisdiction

(a) Description	(b) System Total	(c) Residential Service Sch 1	(d) General Service Sch 11-12	(e) Large Gen Service Sch 21-22	(f) Extra Large Gen Service Sch 25	(g) Potlatch Ex Lg Gen Svc Sch 25P	(h) Pumping Service Sch 31-32	(i) Street & Area Lights Sch 41-49
Plant In Service	702,868,882	284,706,059	68,348,339	159,767,112	56,054,568	107,936,073	11,749,506	14,307,225
Accumulated Depreciation	(221,472,505)	(89,823,549)	(21,532,800)	(48,852,806)	(16,820,733)	(34,746,571)	(3,666,464)	(6,029,581)
Accumulated Deferred FIT	(71,123,638)	(28,720,727)	(6,899,404)	(16,192,722)	(5,690,560)	(10,987,439)	(1,189,235)	(1,443,550)
Miscellaneous Rate Base	8,007,000	2,435,761	582,404	1,834,146	821,856	2,183,374	124,611	24,848
Rate Base	**418,279,739**	**168,597,544**	**40,498,539**	**96,555,730**	**34,365,130**	**64,385,436**	**7,018,418**	**6,858,942**
Revenue From Retail Rates	146,248,000	52,648,000	16,212,000	34,804,000	10,475,000	27,696,000	2,549,000	1,864,000
Other Operating Revenue	21,673,000	7,576,843	1,749,617	4,657,838	2,022,004	5,229,145	332,223	105,330
Total Revenue	**167,921,000**	**60,224,843**	**17,961,617**	**39,461,838**	**12,497,004**	**32,925,145**	**2,881,223**	**1,969,330**
Operation and Maintenance Expense	112,341,399	42,963,059	9,993,402	23,043,440	9,646,670	24,078,941	1,742,909	872,979
Taxes Other Than Income Taxes	7,301,578	2,989,213	730,843	1,722,883	568,411	979,368	126,307	184,553
Other Income Related Items	0	0	0	0	0	0	0	0
Depreciation Expense	19,254,085	7,956,951	1,883,273	4,121,858	1,461,582	3,043,903	312,496	474,022
Income Taxes	5,397,686	1,174,539	995,721	1,966,421	152,562	896,938	130,091	81,415
Total Operating Expense	**144,294,748**	**55,083,761**	**13,603,239**	**30,854,602**	**11,829,225**	**28,999,151**	**2,311,802**	**1,612,968**
Net Income	**23,626,252**	**5,141,082**	**4,358,378**	**8,607,235**	**667,779**	**3,925,995**	**569,421**	**356,362**
Rate of Return	**5.65%**	**3.05%**	**10.76%**	**8.91%**	**1.94%**	**6.10%**	**8.11%**	**5.20%**
REVENUE REQUIREMENT CALCULATION								
Company								
Proposed Rate of Return	9.25%	9.25%	9.25%	9.25%	9.25%	9.25%	9.25%	9.25%
Proposed Return	38,690,876	15,595,273	3,746,115	8,931,405	3,178,775	5,955,653	649,204	634,452
Proposed Total Revenue	182,985,624	70,679,034	17,349,353	39,786,007	15,007,999	34,954,803	2,961,006	2,247,420
Proposed Revenue From Rates	161,312,624	63,102,191	15,599,737	35,128,170	12,985,995	29,725,658	2,628,783	2,142,090
Gross-Up								
Revenue Deficiency	15,064,624	10,454,191	(612,263)	324,170	2,510,995	2,029,658	79,783	278,090
Net to Gross Multiplier	1.564305	1.564305	1.564305	1.564305	1.564305	1.564305	1.564305	1.564305
Revenue Requirement Deficiency	23,565,673	16,353,548	(957,767)	507,100	3,927,963	3,175,005	124,805	435,018
Less CS II Levelization Adjustment	(486,797)	(196,215)	(47,132)	(112,372)	(39,994)	(74,932)	(8,168)	(7,982)
Adjusted Revenue Requirement Deficiency	23,078,876	16,157,333	(1,004,899)	394,728	3,887,969	3,100,073	116,637	427,035
Ratepayers								
Present Revenue From Rates	146,248,000	52,648,000	16,212,000	34,804,000	10,475,000	27,696,000	2,549,000	1,864,000
Proposed Revenue From Rates	169,326,876	68,805,333	15,207,101	35,198,728	14,362,969	30,796,073	2,665,637	2,291,035
Percentage Revenue Increase	15.78%	30.69%	-6.20%	1.13%	37.12%	11.19%	4.58%	22.91%

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IDAHO PUBLIC
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE SUBMISSION OF THE SCHEDULE 66 PCA STATUS REPORT OF AVISTA CORPORATION AND APPLICATION FOR CONTINUATION OF A SCHEDULE 66 POWER COST ADJUSTMENT (PCA) SURCHARGE.

CASE NO. AVU-E-03-6

COMMENTS OF THE COMMISSION STAFF

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Scott Woodbury, Deputy Attorney General, and in response to the Notice of Application, Notice of Modified Procedure, Notice of Comment/Protest Deadline and Notice of PCA/Energy Discussion issued on August 27, 2003 submits the following comments.

BACKGROUND

On August 11, 2003, Avista Corporation dba Avista Utilities (Avista; Company) filed a Power Cost Adjustment (PCA) Schedule 66 Status Report with the Idaho Public Utilities Commission (Commission) and an Application requesting approved recovery of excess power costs deferred through June 30, 2003 and further continuation of a 19.4% ($23.6 million) PCA surcharge currently scheduled to expire on October 11, 2003. Following a public hearing, the 19.4% surcharge was originally authorized by the Commission in Order No. 28876 dated

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October 11, 2001 in Case No. AVU-E-01-11. A 12-month continuation of the surcharge was authorized following a public workshop and comments in Order No. 29130 in Case No. AVU-E-02-6.

STAFF REVIEW

Audit Results

Staff has performed a review and audit of the amounts that went into the deferral balance in the current filing. Staff's review covered expenses incurred for the period July 2002 through June 2003. Staff was able to look at a representative cross section of transactions included in the Purchased Power account (FERC 555), Thermal Fuel account (FERC 501), CT Fuel account (FERC 547) and the Power Sales account (FERC 447). Based on its review of these sale transactions, Staff concludes that the transactions appear reasonable at the time they were entered into. Other than the net fuel expense item that will be discussed in detail later in these comments, Staff finds the amounts recorded to be correct and recommends that they be included in the deferral balance as of June 30, 2003.

The PGE credit recognizes continued 18-year amortization from the monetization of a contract Avista had with Portland General Electric in the last rate case. A line item in the PCA mechanism recognizes this credit by reducing a surcharge or increasing a rebate. The Company received approval to accelerate the amortization from 18 years to fifteen months in order to offset the impact of low water and high market prices. The accelerated amortization of the PGE credit directly benefited the customers as the amount of the PCA surcharge is less and the length of the surcharge is shorter by its inclusion. The amounts recorded in the PCA deferral balance are correct. The PGE credit is $2,309,280 per month and expired at the end of 2002. In this current PCA filing, the PGE credit contributed $13,855,680. Staff notes that this benefit will not be included in future PCA deferrals.

Interest Rate Adjustments

On May 16, 2003, the Company filed an Application requesting that the Commission issue an Order setting the interest rate that applies to the Company's Power Cost Adjustment (PCA) deferral balance at a higher level than the current rate for customer deposits. Staff and the Company agreed to a compromise solution adopted by the Commission in Order No. 29323, dated

August 21, 2003. A 200 basis point increase will be allowed in the interest rate applied to year end deferral balances during recovery based on the first in first out (FIFO) method of accounting. The customer deposit interest rate would continue to apply to new deferral balances accrued during the calendar year. This interest rate methodology would begin January 1, 2003 and continue through June 30, 2005.

Commission Order 29323 was issued after the Company filed its status report in this case. As such, the new interest methodology was not applied in the case as filed by the Company. Staff proposes to include the results of the new methodology in this current PCA year's deferral balance and calculations. The result of Staff's adjustment increases the current year's deferral amount by $256,727. This amount reflects the application of a 200 basis point adder to the current years customer deposit rate of 2%, calculated on the existing balance throughout the months of January through June 2003; and the application of the customer deposit rate of 2% on the new deferrals, which continues to be calculated at simple interest. The Staff's calculations are shown in Attachment A.

Deferral Balance Components

The Company is requesting Commission approval for recovery of the Unrecovered Deferral Balance of $27,843,108 as of June 30, 2003. The Unrecovered Deferral Balance at June 30, 2003 is calculated by starting with the Unrecovered balance at June 30, 2002, adding in the net deferral activity for the current period of July 1, 2002 through June 30, 2003; and subtracting the amortizations related to surcharge revenues.

• Unrecovered Balance at June 30, 2002	$45,600,228
• Net Deferral Activity (July 2002 – June 2003)	6,789,503
• Amortization s Related to Surcharge Revenues (July 2002 – June 2003)	(24,456,623)
• Unrecovered Balance at June 3,0, 2003	$27,843,108

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The net deferral activity consists of several pieces. The Company's Application lists the deferral activity detail that goes into the Net Deferral Activity (July 2002 – June 2003) in the amount of $6,789,503. The net deferral activity is comprised of the follow items and amounts:

• Net Increase in Power Supply Cost	$23,383,629
• Centralia Capital and O&M Credit (Order No. 28876)	($2,817,996)
• PGE Monetization Accelerated Amortization (Order No. 28876)	($13,855,680)
• Small Generation Capital Costs and Interest (Order No. 29130)	($921,184)
• Intervenor Funding Payment (Order No. 29147)	$1,138
• Interest	$999,596

The Centralia Capital and O&M Credit reflects the Centralia capital costs such as return on investment and Centralia O&M expense. Since base rates were set, the Centralia power plant has been sold. The Centralia credit is designed to offset the Centralia revenue requirement that is still part of base rates. The Centralia credit is not subject to 90/10 sharing.

The PGE Monetization reflects the accelerated amortization of the credit balance related to the Monetization of a Portland General Electric (PGE) sale agreement. This credit balance is now zero.

The Small Generation Capital Costs and Interest were disallowed in the last PCA filing, Case No. AVU-E-02-6. The costs included in the deferral balance that represented capital costs, and the interest thereon, were excluded from deferral balance and subsequent recovery.

The intervenor funding payment resulted from Order No. 29147 in Case No. GNR-E-02-1 dated October 31, 2002, an Order dealing with published rate eligibility and contract length for PURPA projects. The Commission directed the three participating utilities to equally share the intervenor funding amount, to book the payment as a purchased power expense and" ... to recover same in their next Power Cost Adjustment (PCA) filing or general rate case."

The largest component of the net deferral activity is the Net Increase in Power Supply Cost. The total net increase in power supply cost, $23, 383,629, is comprised of the following items:

1. Purchased Power	($7,083,766)
2. Thermal Fuel	($5,942,944)
3. CT Fuel	($948,195)
4. Sales for Resale	$21,605,030
5. PGE Capacity Revenue True Up	($2,483,328)
6. Potlatch 25 aMW	$4,260,572
7. Kettle Falls Bi-Fuel	$1,102,506

8. Net Fuel Expense – Loss on Natural Gas Resold	$11,817,650
9. Idaho Retail Revenue Adjustment	$651,882
10. Wood Power Inc. Amortized Expense	$352,788
11. Reverse Coyote Test Power Sales	$51,434

1. Purchased Power represents the difference in costs the Company incurred for power purchases when compared to base rates. The negative amount represents a benefit to ratepayers – the Company bought less power in the market than is currently built into base rates.
2. Thermal Fuel is the amount spent for fuel, primarily coal, used to produce electricity. This item is the difference in costs the Company incurred for thermal fuel when compared to base rates. The negative amount represents a benefit to ratepayers – the Company bought less coal than is currently built into base rates.
3. CT Fuel is the cost of natural gas burned in the Company's combustion turbines. This amount represents the difference in costs the Company incurred for CT fuel when compared to base rates. The negative amount is a benefit to ratepayers.
4. Sales for Resale represents revenues the Company is able to generate through long-term and short-term off-system sales. These revenues reduce the revenue requirement for ratepayers. The positive amount represents a decrease in off-system sales. This amount represents an increased cost to customers over what is currently built into rates.
5. The PGE Capacity Revenue True up adjustment was approved in Order 28775, Case No. AVU-E-01-01, when the PCA mechanism was modified. The Adjustment records an additional amount of revenue to the recorded revenue in Account 447 so that there is no PCA impact of the PGE capacity sale.
6. The Potlatch component is a direct assignment to Idaho of Potlatch costs and revenues (Lewiston facility).
7. The Kettle Falls Bi-Fuel component is the final payment on the Company's lease of temporary generators for the Kettle Falls Bi-Fuel project. Temporary generators were leased and placed at Kettle Falls to avoid additional high-cost purchases of energy from the short-term wholesale markets. The projects represented the lowest cost resource options available at the time. In Order No. 29130, Case No. AVU-E-02-6, the Commission found that the lease costs for these temporary generators was properly included in the PCA.
8. Net Fuel Expense is discussed in more depth in the next section.

9. The Idaho Retail Revenue Adjustment is an adjustment for changes in load. If the load grows, revenue is added, if the load declines, there is an adjustment to reflect the decreased load. A revenue credit of retail load is computed using a variable cost of power supply of 21.23 mills/kWh multiplied by the growth in load.
10. Wood Power operated a PURPA qualified wood waste powered generation facility at Plummer, Idaho. Washington Water Power entered into a power sales agreement with Wood Power on August 19, 1982 to purchase the energy and capacity from that facility. On September 30, 1996, Washington Water Power entered into an agreement with Wood Power and Rayonier terminating the 1982 power sales agreement. In Order No. 26751, Case No. WWP-E-96-8, the Company received authorization for rate making and accounting treatment of the buy-out of the Wood Power, Inc. contract. The Commission found that the deferral and amortization of the buy-out over eight years was reasonable. This amount is the current year's amortization of the buy-out of that contract.
11. The Coyote Springs test power sales are included in the Sales for Resale accounts. When testing was being done at the Coyote Springs II facility, the power was sold and the sales recorded in the Sales for Resale account. This adjustment removes them from the PCA deferral balance.

A significant portion of the net increase in Power Supply Costs is due to the expiration of long-term power sales contracts. The expiration of profitable contracts reduced Sales for Resale revenue dramatically. In the PCA, Sales for Resale revenue is an offset to Power Supply Costs. The loss of revenue from expired contracts is partially offset by reductions in fuel costs and Purchased Power costs. Total long-term sales contracts fell from twenty-one in the base case to eight in June of 2003. The reduction in recent time periods of energy sales and associated revenue is shown on Attachment B.

Net Fuel Expense

Avista Utilities has an obligation to provide electrical service to its customers. To satisfy this obligation, the Company both generates and buys electricity. Part of the utility's generating resources are fueled by natural gas. When gas prices are low enough that electricity can be generated at a cost below the cost of buying electricity on the market, the Company buys gas and uses it to produce electricity.

In the last PCA case, AVU-E-02-6, Staff questioned the circumstances surrounding acquisition and later sale of natural gas purchased by the Company to fuel the Coyote Springs II CCCT (Combined Cycle Combustion Turbine). The Company maintains that at the time natural gas was purchased, it was anticipated that Coyote Springs II would be operational and more economical to operate than making market energy purchases. As it turns out, Coyote Springs II was neither operational nor was it economical to use the gas at the Company's other facilities, given the price of the gas with previously purchased fixed-for-floating financial swaps. The effect is an abnormally high percentage of hedged gas to serve available resources at prices found to be uneconomical when compared to energy purchased from the market.

In Case No. AVU-E-02-6, Staff proposed that the Commission withhold judgment on $578,748 in net fuel expense incurred in June of 2002 to serve Coyote Springs until a more complete evaluation was conducted regarding anticipated online dates, reasons for the operational delay and timing of the sale of gas acquired for use at the plant. Pending further investigation, the Commission in its Order removed the $578,748. As part of its current PCA investigation and as a result of concerns raised regarding the circumstances surrounding acquisition and sale of natural gas in Case No. AVU-E-02-6, Staff has completed a comprehensive review of gas purchase and sales transactions that generated losses on fuel resold and the excess net fuel costs requested for recovery in this case.

In March of 2001, Avista entered into two contracts to secure gas and gas transportation for its Coyote Springs II gas fired power plant. Initially Coyote Springs II was scheduled for testing in early 2002 and was expected to be commercially available in July of 2002. The two purchases for Coyote Springs II, with five corresponding financial swap transactions, are of primary concern to Staff. These purchases and financial swaps are shown in detail on Staff's Confidential Attachment C. The first gas supply contract (Deal A) was to be delivered November 1, 2001 through November 1, 2004. The fixed-for-floating financial swaps associated with this supply contract consist of two transactions. See Confidential Attachment C for specific volumes and prices. Since the delivery period did not begin for another 6 months, the price for October 2004 was locked 3 1/2 years into the future without additional documentation showing analyses beyond October 2002. Additional analyses that should have been fully documented with the swap order should include volatility analyses, price trend analyses and load requirements for the time period involved.

The second gas supply contract (Deal B) was for delivery to begin June 1, 2002 and continue through October 31, 2003. Avista entered into two fixed-for-floating financial swap contracts that were subsequently combined into one contract, for the entire delivery period. This transaction locked in the price of gas for a period of 17 months. Since the delivery period did not begin for another 13 months, the October 2003 price was locked 2 1/2 years into the future.

Gas from both contracts is sufficient to operate Coyote Springs II at its full 180 MW generating capacity through October 31, 2003. At the time the Deals were first entered into and at the time the prices were locked, forward prices for electricity for an 18-month period were expected to be very high and the Company expected substantial purchased power cost savings and/or sales for resale revenues from the gas purchases. A portion of these savings or revenue credits would have flowed through the PCA to benefit Idaho ratepayers and a portion would have benefited Company shareholders. During June of 2001, day ahead electric market prices fell below $100/MWh for the first time in a year and by September they were approximately $25/MWh, which is near the historic normal wholesale electric price. See Staff Attachment D. Given approximately $6.00 gas, the drop in electric prices made it uneconomical to operate any of Avista's gas fired plants to make electricity. Instead Avista simply purchased its power needs on the electric market and sold the gas back into the gas market at a loss because gas prices had also declined. See Staff Attachments E through H.

In Avista's PCA filing last year, which covered the time period July 2001 through June 2002, losses on the sale of gas from Deal A amounted to approximately $5.6 million and were approved for recovery. (See Confidential Attachment I) The loss on Deal B last year was approximately $0.6 million. This amount was not recovered in the last PCA, but deferred to the current PCA year for evaluation. In this year's PCA, which covers July 2002 through June 2003, Avista has included $11.8 million in losses due to gas sales. It is likely that there will be more losses on the sale of this gas through the end of the longest contract, which ends on November 1, 2004.

In Order No. 29130 the Commission directed Staff to investigate and assess the reasonableness of Avista's Risk Management Policy and how it affects the Company's short-term resource acquisition decision and to submit its findings and conclusions in the Company's next PCA review. Staff has completed its review and incorporates its findings and conclusions in these comments. Avista has an electric Risk Policy for managing the financial risk associated with providing electric energy to its customers. (Confidential Attachment J; Avista Corp.'s Energy Resources Risk Policy.) The policy addresses the purchase and sale of electricity as well as the purchase and sale of natural gas acquired to generate electricity. In general, this Policy defines a mechanism that eliminates differences between loads and resources as the actual time of need approaches. The Company's Risk Policy typically extends 18 months out, and tracks surpluses and deficiencies month by month down to projected needs in the coming month. Avista's Risk Policy (dated November 9, 2000, page 1 of 15) specifically states, "This Policy is intended to focus on short-term power and natural gas supply management, meaning the period of eighteen months forward from any current date, as they relate to meeting near-term energy load obligations." Deficits are eliminated with relatively small purchases that may occur over several months. Surpluses are eliminated with sales in the same way. The plan does not take a price view - that is, there are no purchases or sales made based on speculative judgments as to whether electric market prices are going up or coming down. Surpluses or deficits are systematically eliminated over time without speculation with regard to price. Such a plan is designed to reduce the financial risks that might otherwise be associated with large quantity, long-term sales or purchases made at a single point in time.

In theory, Staff does not oppose entering into financial swaps or hedges to fix the price of gas. However, Staff is concerned about the length of the swaps that Avista entered into and the apparent lack of additional support 2 ½ and 3 ½ years in the future. The Company previously received from the Commission an accounting Order authorizing the deferral of the costs of a financial hedge for Avista's gas operations; however, that financial transaction was entered into in December 2000 for delivery during January through March 2001. That transaction occurred shortly before delivery was taken, and only covered a period of 3 months. The financial swaps that Avista entered into for the March 9, 2001 transaction covered 3 years, and delivery was not to begin for another 6 months in the future. Because the swaps locked prices for the last month 3 ½ years out, these swaps were inherently risky instruments.

The gas deals that Avista entered into were unusual. Avista Electric had no recent history of entering into purchase or sales arrangements that went outside of its normal 18-month position report planning period. Avista Gas Operations did not make purchases outside of a 12-month period that it uses to balance its gas need for its gas customers.

Staff believes that the losses on the sale of gas from the two purchases resulted from substantial risks that the Company took when it locked in the price for large quantities of gas for a period of time up to 3 1/2 years after the date of the purchase. The risk substantially stems from the price paid, the fact that the price was established at only 2 points in time approximately 30 days apart, gas price levels and trends over time, the volume of gas purchased, the length of forward analysis and the duration of the purchases.

Prices averaging $6.00 per dth are historically high. Gas prices for the period of months leading up to the Company's purchases had been very high and very volatile. The Company should have known that locking in gas prices at historical highs based primarily on long-term future power prices with volatile and/or illiquid forward markets was very risky.

The March 2001 contracts for gas delivery assured the gas and transportation. The April and May 2001 financial swaps were entered into to lock in the price of gas. Locking in a high purchase price at 2 points in time approximately one month apart for long-term purchases does not capture the risk reducing benefits of layering or cost averaging that would be captured with monthly purchases or reduced volumes at fixed prices spread over the period of power need.

Risks could have been reduced if smaller quantities of 2, 3 or 5 thousand dth/day had been purchased over time instead of 4 financial swaps entered into over the period of a month totaling 40,000 dth/day (decatherm/day) for much of the entire 3-year period. Not only did the Company lock into the purchase side of the gas transaction at historically high gas prices, in large volumes at essentially one point in time, it failed to mitigate the risk by also securing some mechanism to lock in the power sale side of the transaction for the excess energy. If the Company had locked into forward electricity sale agreements for the excess power generation, some of the risk of the gas fixed-for-floating financial swap purchase could have been mitigated. The Company appears to have done nothing to mitigate the risk of locking in the price of the gas. Historical trends and changes in rig counts and production levels support that prices should decline and if the Company continued with the initial Deals, i.e. index plus a small adder, the risk would have been significantly smaller. If the financial transactions had never taken place, the gas, if burned, would have been purchased at a price within pennies of the spot price, and if the gas had been sold, it would have been sold at a price within pennies of the spot price. These risk considerations are the type of issue where stakeholder and customer input into the Risk Policy would be beneficial.

The Company's decisions were contrary to the previously cited principals of good risk management. The Company's Risk Policy allows for purchases that exceed 18 months in the future with proper authorization. These purchases met the Company's authorization requirements. However, Staff contends the documentation to support these substantially longer transactions is lacking. The Deal tickets provided some explanation as to why the long-term purchases were made at this point in time. The workpapers reiterate again and again that the purchases were entered into for the sole purpose of securing financing for the Coyote Springs II Project. The financial swaps were completed on May 10, 2001. Board Minutes and other documents reflect that the financing package for construction financing for the development of the Coyote Springs II Project was proposed to and approved by the Board of Directors at the quarterly meeting on May 11, 2001. The primary reason for locking in gas supply and price for the Coyote Springs II Project appears to be for the purpose of obtaining outside financing for the project. This may explain why the Company undertook financial transactions that Staff believes were largely outside its existing Risk Policy. To the extent the transactions were made for the purpose of financing Coyote Springs II, they were to meet Avista's cash flow requirements that were not necessarily associated with utility operations. Ironically, the project financing was not achieved with this approach.

Whether the transactions were implemented for the purpose of obtaining project financing or not, the effect of undertaking financial swaps beyond the generally accepted period of 18 months as specified in the Company's Risk Policy was $39,465,033 in losses on a system basis. This amount, which translates to $11,785,048 on an Idaho jurisdictional basis after sharing, consists of losses during the period of July 2002 through June 2003 for the swaps entered into on April 10, 2001 and May 2, 2001, and losses associated with swaps during the months of June 2002 through June 2003 entered into on April 11, 2001, May 10, 2001 and rolled into one swap on June 20, 2002. As previously mentioned, losses on these financial swaps during future PCA periods is also likely.

Deal B Adjustment

However, while Staff has been critical of the Company with respect to its overall gas acquisition approach for Coyote Springs II and questions the reasonableness of the long-term financial transactions, it does not recommend a cost recovery adjustment based on total gas sales losses during the PCA period at issue in this case. Instead, Staff limits its recommended adjustment to losses associated with Deal B during the period from June 2002 through June 2003.

Gas losses incurred under Deal B carry all of the risk concerns previously identified with one additional concern, the purchase put the Company in a long position outside of established risk management limits. Staff recommends that losses on the sale of Deal B gas not be allowed to be deferred for PCA recovery.

After Avista entered into Deal A on March 9, 2001, the next Company position report generally showed that Avista's resource/load balance stayed within established risk guideline limits for the delivery period. When Avista entered into Deal B the position reports showed Avista to be surplus beyond the established limits. Avista resisted selling the above limit energy for a period of time by getting a waiver from its Risk Management Committee but eventually sold the gas and took the loss. At this point in time all the gas purchased under Deals A and B was sold at a loss and energy needs were purchased from the electric market because it was the most economic choice. Less electrical energy was purchased than could have been generated with the gas because the Company did not need all the energy the gas would have generated. The additional gas purchase activity more clearly falls under the definition of taking a "Speculative Position" as defined on p. 11 of 15 in the Company's Risk Policy. It is speculative because the generation is not needed for load; it focuses on future price changes and is not documented and shown to reduce "Business Risk."

The Company provided Staff with a sample of daily Position Reports and Position Limit Charts. The Position Limit Charts show projected energy surpluses and deficits for Heavy Load Hours (HLH) and Light Load Hours (LLH) in average Megawatts for a period of 18 months along with their relationship to risk limits. Confidential Attachment K, pages 1 through 4 are copies of Position Limit Charts on 4 selected days. Page 1 shows the Company's projected positions on March 7, 2003, which is prior to either of the gas purchase deals. For the period beginning November 2001 and beyond it shows small surpluses and deficits except for two substantial deficits that are outside the short position limits. Page 2 shows the Company's projected positions on March 21, 2001. This chart shows the Company's projected positions after it acquired gas under Deal A but before it entered into Deal B. The purchase of gas to be used to generate energy moved all of the Company's 2002 positions in the surplus direction, as one would expect. At this point in time, the chart shows no long or short positions outside of risk management limits. Page

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3 shows the Company's projected positions on March 28, 2003. At this point in time the Company had entered into Deal B, which was the additional gas purchase that began in June of 2002. At this point in time all 2002 positions are surplus and LLH in the third quarter are surplus beyond the limit. To be surplus outside of the risk management limits in one quarter 18 months out does not cause Staff a great deal of concern. However, it is the only full quarter shown on that chart that captures the effect of both gas purchases. In order to show the effect on the Company of both gas purchases the next position limit chart is for June 20, 2001. Staff proposes that this chart be viewed in three parts. July 2001 through November 2001 show positions that are long and short but all within position limits. December 2001 through May 2002 show the time period that Deal A gas is to be delivered. Positions are long and in 2 months slightly outside of position limits. June 2002 through December 2002 is the period of time when gas is to be delivered to generate power under both Deal A and Deal B. In general, positions are quite long and in all month HLH or LLH energy or both are outside of position limits.

The calculation of the loss on the gas sales is shown on page one of Staff Confidential Attachment I. Staff calculated the purchase amounts of Deal A and B by multiplying 20,000 dth/day times the price, times the number of days in each month for each deal. Staff calculated the sale amounts by multiplying the 20,000 dth/day times the number of days in each month times the average weighted price for the month. Staff used workpapers supplied during the audit to calculate the average monthly sales price received for sales of gas purchased and resold. When the Company prepares DJ 042 entries (Diarized Journal 042), the average price per therm that the gas is sold at is calculated. The worksheets Staff obtained during the audit provided the information necessary to calculate sales price of the gas resold on a monthly basis. Staff used that amount to calculate the loss on the sale of the gas.

The loss on the sale is the monthly difference between the purchase price of the 20, 000 therms per day of gas, and the sales price of the 20,000 therms per day of natural gas.

Staff separated the loss between Deal A and Deal B. The amounts are then multiplied by the jurisdictional allocation factor (33.18%, the Production and Transmission allocation ratio) and then multiplied by 90% to reflect the customer portion after the 90/10 sharing.

Staff calculated the loss on each Deal for the months of November 2001 through June of 2003. Staff calculated the loss on each Deal for the months of November 2001 through June of 2003. Staff recommends disallowing the losses from Deal B for the months of June 2002 through

June 2003, in the amount of $5,849,100, with associated carrying charges of $87,343, for a total adjustment of $5,933,433.

Staff's decision to limit its recommendation to the losses associated with Deal B is due to several factors. The most obvious is the market conditions faced by the Company at the time the transactions were made. Forward prices for both natural gas and electricity were high for periods beyond 18 months. The Company's existing Risk Policy was sufficiently broad to allow deviation with sufficient authorization and without specific documentation. While the Policy needs to be modified in this regard, Staff does not necessarily believe that an adjustment incorporating all losses beyond the 18-month policy period is warranted. Finally, Staff cannot ignore the financial impact that such an adjustment could have on the Company. While Avista's financial situation has improved since 2001, and Staff believes the Company can and should absorb the losses associated with Deal B, cost recovery adjustment beyond that level could cause significant negative impact.

Rate Impact

Staff proposes that the loss on the sale of gas associated with Deal B be removed from the PCA deferral account along with associated interest.

The swaps on Deal B were entered with Avista Energy. The electric operations have claimed no dealings with Avista Energy so proper pricing mechanisms with safeguards have not been established. Absent an approved mechanism, the affiliate transactions with Avista Energy should be priced at the lower cost or market. Therefore, the losses on Deal B should be repriced at market with the Company absorbing the loss rather passing it to customers through the PCA.

The loss on the sale of gas captured in the Idaho PCA deferral balance amounts to $5,849,100 and reduced interest amounts to $87,343, which reduces the deferral balance to $21,906,665 dollars as of the end of June 2003. Existing PCA rates are designed to recover approximately $23.6 million in a year. If PCA rates were adjusted based on Staff's calculations the rates would be reduced from 19.4% to 18.0 %. However, Staff proposes that existing PCA rates be continued until the next PCA regardless of the final decision reached in this case. Rates can remain unchanged because in the future any differences between deferred costs and PCA revenues including accrued interest will be trued-up. Staff Attachment L shows the deferral balance as a result of Staff's adjustments.

CONSUMER ISSUES

The Application filed by Avista on August 11, 2003 contained both the customer notice and press release. Both met the requirements of IDAPA 31.21.02.102. Avista sent its customer notifications beginning with customer bills on August 12, 2003 and ending September 11, 2003.

The IPUC held public workshops in both Lewiston and Coeur d'Alene regarding Avista's proposed continuation of its 19.4% surcharge. One customer attended the Lewiston workshop and no customers attended the Coeur d'Alene workshop.

From the time Avista filed its PCA and through September 29, 2003, the Commission received 6 written comments from customers. The deadline for filing comments is September 30, 2003. None of those who commented were in favor of the continuation of the surcharge.

One customer suggested in her comments that Avista implement a program similar to Verizon's ITSAP program. The Idaho Telecommunications Service Assistance Program (ITSAP) participants save $13.62 per month on local telephone bills. The program is mandated by *Idaho Code* and monies are recovered from residential and wireless telephone users; it is not a program initiated by Verizon. While some states have additional funds available for energy assistance for low-income residents, Idaho does not mandate electric companies in Idaho to collect funds from residential customers to assist low-income customers with energy costs. The customer added in her comments that she qualifies for and receives heating bill assistance from the federally funded energy assistance program called Low Income Home Energy Assistance Program (LIHEAP).

In July of 2003, Avista donated $50,000 to Project Share in north Idaho. Project Share is a fuel fund that helps qualified customers pay heating bills. Although some states mandate electric companies to donate to fuel funds, Idaho does not. Project Share monies come from the utility company, customers, and organizations who voluntarily give donations. The administrator for Project Share in northern Idaho said the funds this year arrived from Avista in July and some were used immediately to help low income customers pay electric bills who needed power connected to run electric fans during this past summer's exceptionally high temperatures. Customers may receive financial assistance from both LIHEAP and Project Share. Project Share is sometimes used to assist those who might be in a wage group slightly above the income requirements needed to receive federal LIHEAP funds.

Avista also continues to offer rebate programs to customers who convert to energy efficient heating or water heating equipment.

Avista continues to promote Comfort Level Billing to help customers level out payments over a twelve-month period. Comfort Level Billing is often a helpful budgeting tool for customers who have difficulty paying high bills in the heating months and yet have low electric bills in the summer. Approximately 13% of Avista's customers use Comfort Level Billing.

Since the last PCA was approved in October of 2002, the Commission's Consumer Assistance Staff received 150 complaints and inquiries from customers regarding electricity issues. Forty-five percent of those complaints and inquiries were related to credit and collection issues, with the majority being about disconnection for non-payment of the customer's electric bill. (These figures are typical for Idaho electric companies). The number of complaints and inquiries regarding electric issues decreased by 25% between the months of October 2002 through September 2003 when compared with the corresponding time period of October 2001 through September 2002. In both time periods, approximately one-half of the complaints were related to disconnection of service for non-payment.

RECOMMENDATIONS

Staff proposes that the Commission accept the filing with the following recommendations and modifications. Staff specifically recommends that:

1. The current surcharge be continued until the next PCA filing regardless of the final decision reached by the Commission in this case. Staff also recommends any actual remaining deferral balance at June 30, 2004 be subject to review by the Commission prior to establishing a surcharge for an additional period of time, as provided for in Order No. 28876, Case No. AVU-E-01-11.
2. The net fuel expense for losses on natural gas CT fuel sold rather than burned under "Deal B" be denied for recovery in the PCA in the amount of $5,849,100 and interest.
3. That the deferral balance be modified to include Staff's adjustments and corresponding adjustments to the carrying charges.
4. The Company work with the Commission Staff and customers in developing an acceptable Risk Policy for the Utilities division of Avista Corporation.

Exhibit No. 139
Case No. AVU-E-04-1/
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K. Hessing, Staff
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Respectively submitted this 30th day of September 2003.

Scott Woodbury
Deputy Attorney General

Technical Staff: Kathy Stockton
Marilyn Parker
Keith Hessing

i:umisc/comments/avue03.6swklskhmp

Exhibit No. 139
Case No. AVU-E-04-1/
AVU-G-04-1
K. Hessing, Staff
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Idaho Public Utilities Commission
Staff Adjustment A
Interest Calculation
Avista Utilities Idaho PCA
Case No. AVU-E-03-06

6/30/2002	Balance excluding interest		41,568,103	Interest
Jul-02	Deferral		927,566	
	PGE amortization - RJ216		(2,309,280)	
	Surcharge Amortization		(1,822,555)	
7/31/2002	Balance before interest		38,363,834	
	Interest			138,560
7/31/2002	Balance excluding interest		38,363,834	
Aug-02	Deferral		1,885,964	
	PGE amortization - RJ216		(2,309,280)	
	Surcharge Amortization		(1,962,847)	
8/31/2002	Balance before interest		35,977,671	
	Interest			127,879
8/31/2002	Balance excluding interest		35,977,671	
Sep-02	Deferral		1,372,898	
	PGE amortization - RJ216		(2,309,280)	
	Surcharge Amortization		(1,917,598)	
9/30/2002	Balance before interest		33,123,691	
	Interest			119,926
9/30/2002	Balance excluding interest		33,123,691	
Oct-02	Deferral		2,416,760	
	PGE amortization - RJ216		(2,309,280)	
	Surcharge Amortization		(1,821,411)	
10/31/2002	Balance before interest		31,409,760	
	Interest			110,412
10/31/2002	Balance excluding interest		31,409,760	
Nov-02	Deferral		1,364,437	
	Intervenor Funding Order		1,137	
	PGE amortization - RJ216		(2,309,280)	
	Surcharge Amortization		(2,069,140)	
11/30/2002	Balance before interest		28,396,914	
	Interest			104,699
11/30/2002	Balance excluding interest		28,396,914	
Dec-02	Deferral		3,348,526	
	PGE amortization - RJ216		(2,309,280)	
	Surcharge Amortization		(2,317,523)	
12/31/2002	Balance before interest		27,118,637	
	Interest			94,656
12/31/2002	Balance excluding interest		27,118,637	
Total Interest to Date				$3,807,074
Deferral Balance at 12/31/02 with Interest				$30,925,711
Begin New Interest Calculation on Old Balance, Continue Simple Interest on New Balance				
Jan-03	Deferral		$30,925,711	3,454,572
	Surcharge Amortization		(2,421,489)	
1/31/2003	Balance before interest		28,504,222	0
	Interest		$103,086	0
1/31/2003	Balance excluding interest	Balance	28,607,308	3,454,572
Feb-03	Deferral		0	1,245,118
	Surcharge Amortization		(2,227,385)	
2/28/2003	Balance before interest		26,379,923	4,699,690
	Interest		$95,358	5,758
2/28/2003	Balance excluding interest	Balance	26,475,281	4,699,690
Mar-03	Deferral		0	1,626,742
	Surcharge Amortization		(2,184,726)	
3/31/2003	Balance before interest		24,290,555	6,326,432
	Interest		$88,251	7,833
3/31/2003	Balance excluding interest	Balance	24,378,806	6,326,432
Apr-03	Deferral		0	332,541
	Surcharge Amortization		(2,052,187)	
4/30/2003	Balance before interest		22,326,619	6,658,973
	Interest		$81,263	10,544
4/30/2003	Balance excluding interest	Balance	22,407,882	6,658,973
May-03	Deferral		0	1,488,717
	Surcharge Amortization		(1,864,170)	
5/31/2003	Balance before interest		20,543,712	8,147,690
	Interest		$74,693	11,098
5/31/2003	Balance excluding interest	Balance	20,618,405	8,147,690
Jun-03	Deferral		0	1,101,792
	Surcharge Amortization		(1,885,592)	
6/30/2003	Balance before interest		18,732,813	9,249,482
	Interest		$68,728	13,579
6/30/2002	Balance excluding interest	Balance	18,801,541	9,249,482
	Simple interest, 4% and 2&			$744,944
	Compound interest, 4%			$511,379
	Total Interest for 2002-2003 PCA Period			$1,256,323
Company accumulated interest for Jan1, 2003 through June 30, 2003				$999,596
	Difference due to Case No. AVU-E-03-04			$256,727

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Attachment A
Case AVU-E-03-6
Staff Comments
9/30/03

AVISTA UTILITIES LONG-TERM POWER SALES

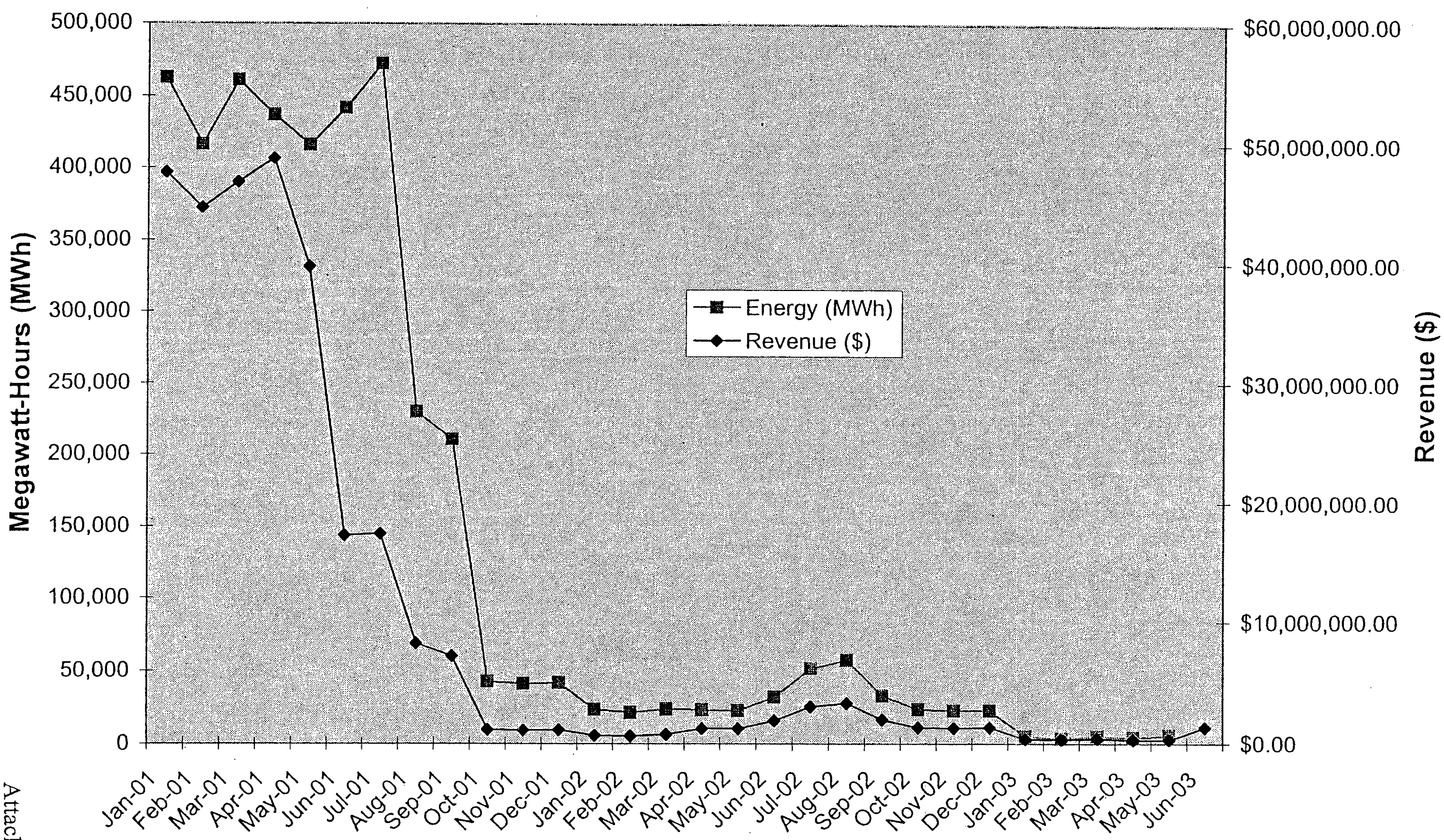

Exhibit No. 139
Case No. AVU-E-04-1/
AVU-G-04-1
K. Hessing, Staff
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Attachment B
Case No. AVU-E-03-6
Staff Comments
9/30/03

ATTACHMENT C IS CONFIDENTIAL

Monthly Average Mid-Columbia Price

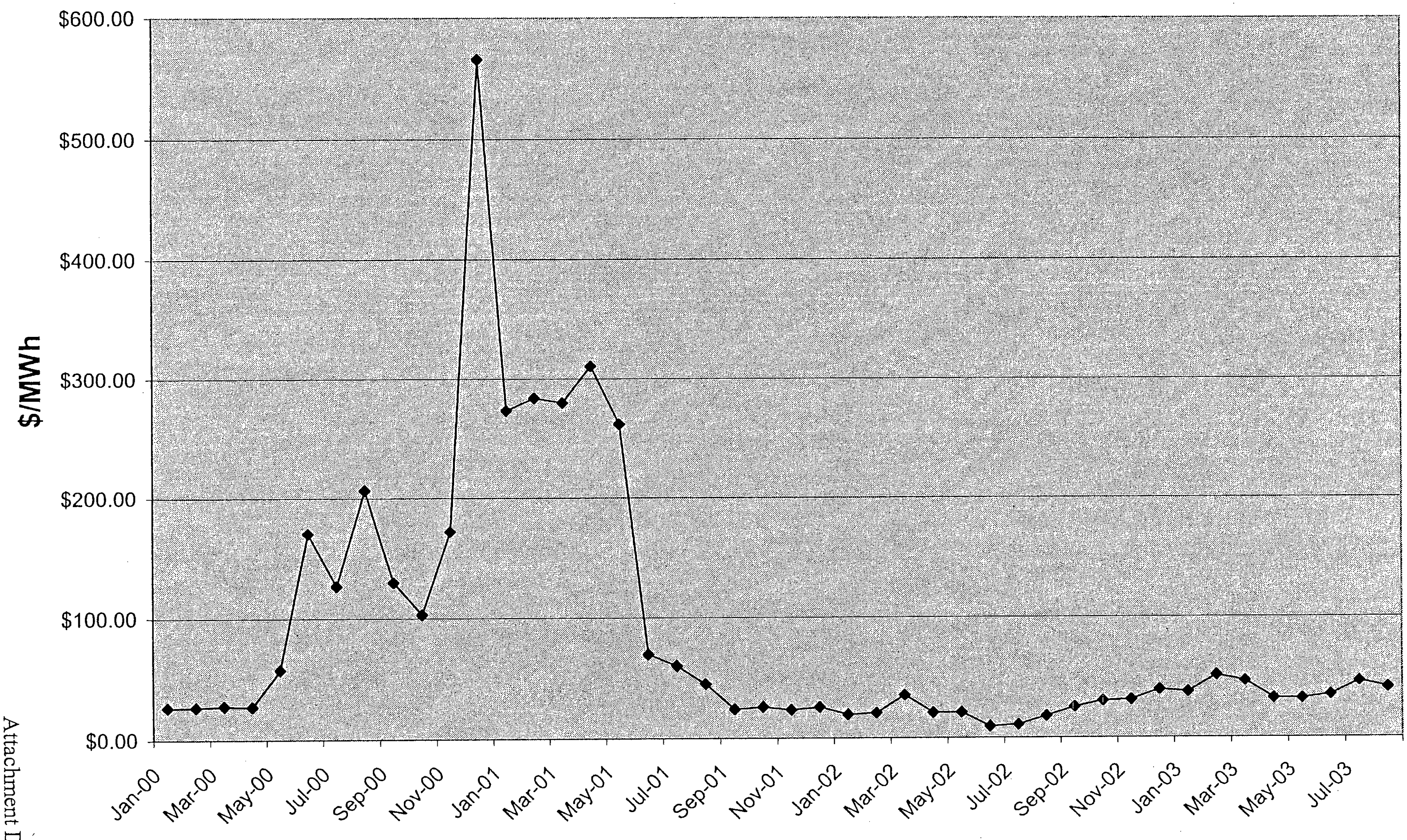

Exhibit No. 139
Case No. AVU-E-04-1/
AVU-G-04-1
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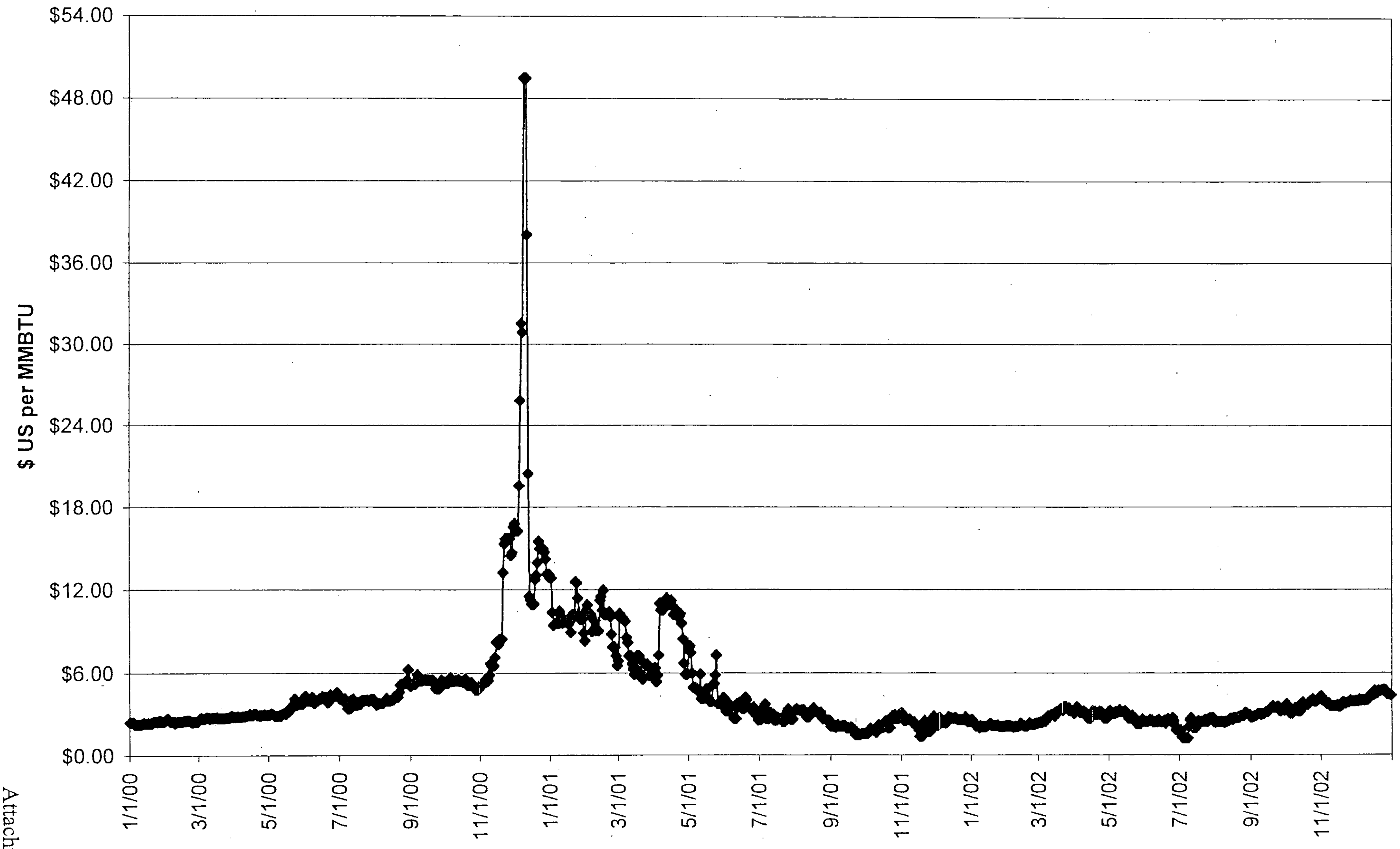
Attachment D
Case No. AVU-E-03-6
Staff Comments
9/30/03

Historical Daily Gas Prices at Malin, Oregon



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K. Hessing, Staff
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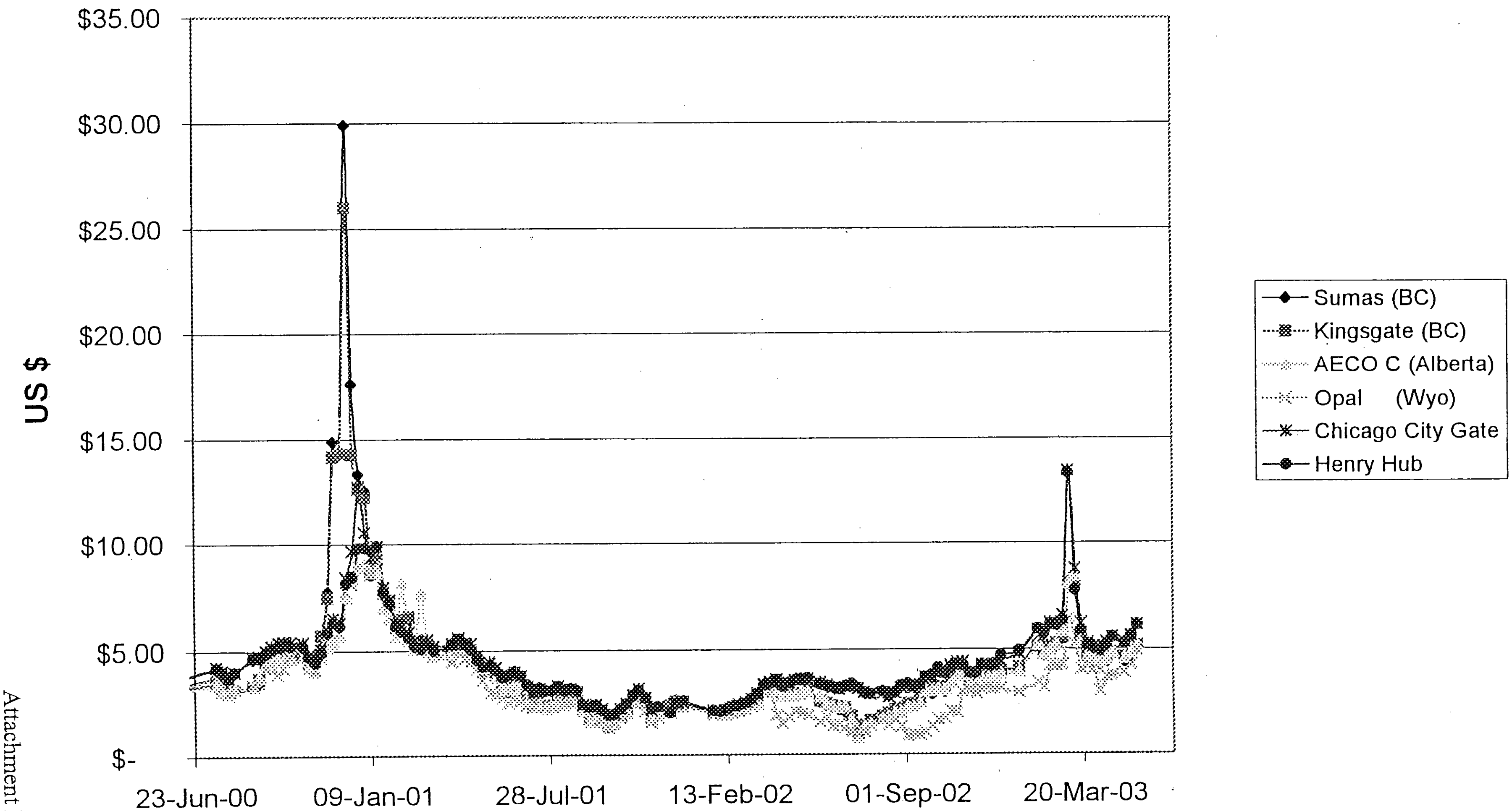
Attachment E
Case AVU-E-03-6
Staff Comments
9/30/03

Natural Gas Price Per MMBtu US $ at selected Hubs and City Gates



Source: Natural Gas Week

Exhibit No. 139
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K. Hessing, Staff
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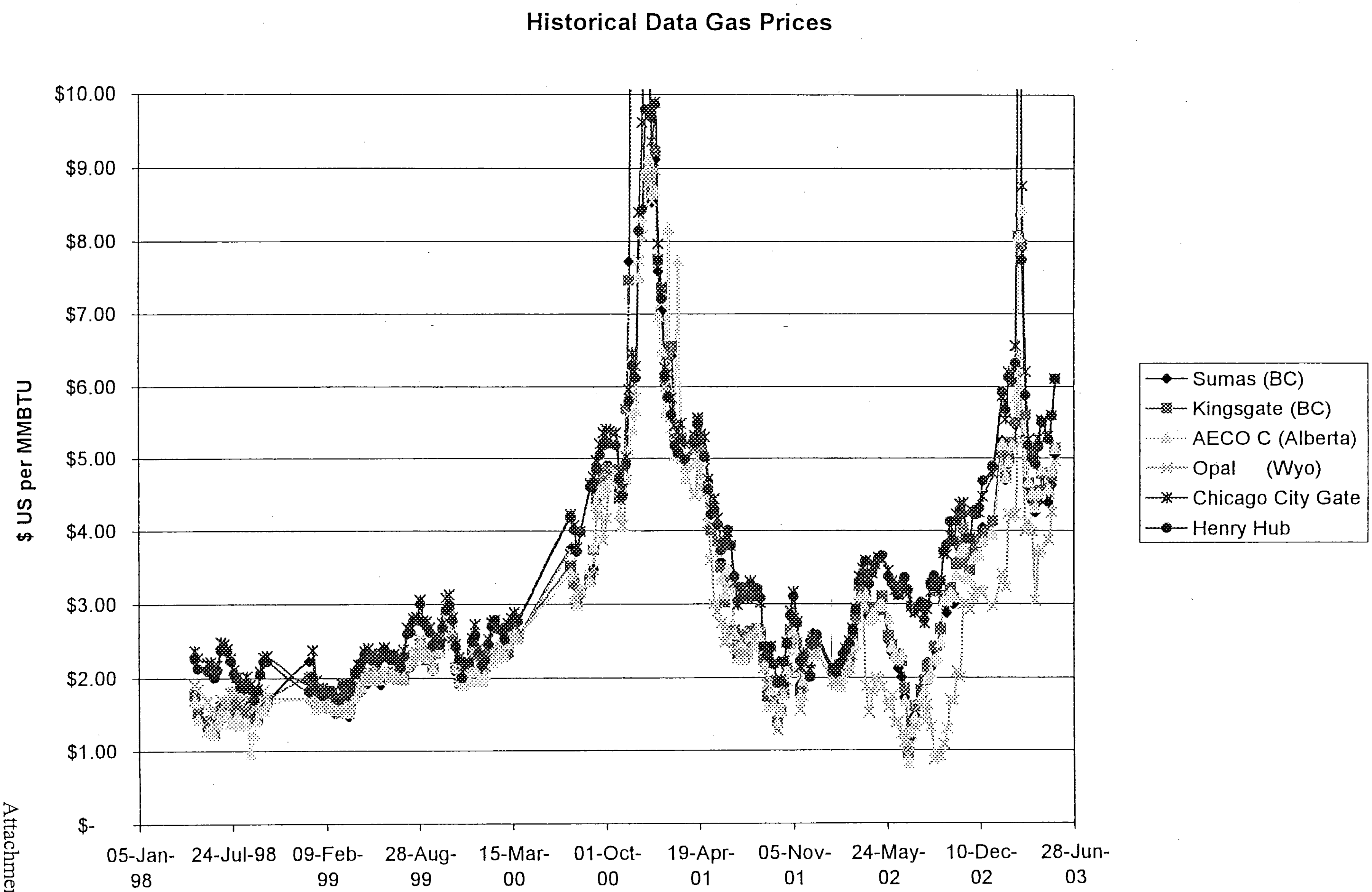
Attachment F
Case AVU-E-03-6
Staff Comments
9/30/03



Attachment G
Case AVU-E-03-6
Staff Comments
9/30/03

Exhibit No. 139
Case No. AVU-E-04-1/
AVU-G-04-1
K. Hessing, Staff
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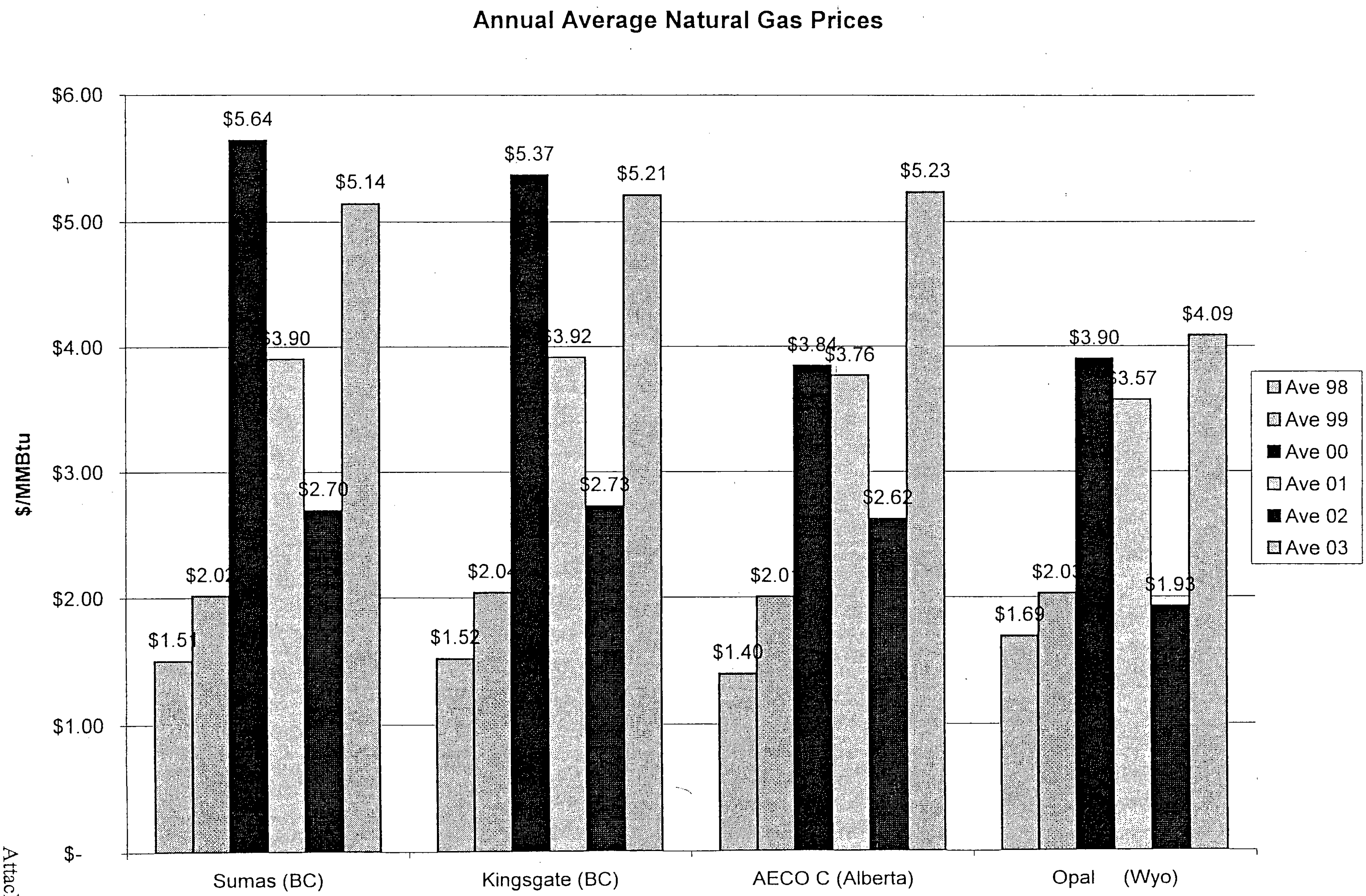

Exhibit No. 139
Case No. AVU-E-04-1/
AVU-G-04-1
K. Hessing, Staff
6/21/04 Page 25 of 30

Attachment H
Case AVU-E-03-6
Staff Comments
9/30/03

ATTACHMENT I IS CONFIDENTIAL

ATTACHMENT J IS CONFIDENTIAL

ATTACHMENT K IS CONFIDENTIAL

Idaho Public Utilities Commission
Staff Adjustment L
Avista Utilities Idaho PCA
Deferred Cost Balances
Case No. AVU-E-03-06

Company 2002-2003 Deferral Calculation	
Deferral Activity Detail	
Net Increase in Power Supply Cost	$23,383,629
Centralia Capital and O&M Credit	-$2,817,996
PGE Monetization Accelerated Amortization	-$13,855,680
Transfer Small Generation Capital Costs and Interest	-$921,184
Intervenor Funding Payment	$1,138
Interest	$999,596
Company Deferral for July 2002 - June 2003 period	$6,789,503
Staff 2002-2003 Adjustment to Deferral Balance	
Staff Adjustment to Loss on Natural Gas Sales	-$5,849,100
Interest Adjustment due to Staff Adjustment	-$87,343
Adjust Interest Calculation for Case No. AVU-E-03-04	$256,727
Total Staff Adjustment to Company Deferral for 2002-2003	-$5,679,716
Staff Proposed Deferral for July 2002 - June 2003	$1,109,787
Unrecovered Balance at June 30, 2002	$45,600,228
Staff Net Deferral Activity (July 2002 - June 2003)	$1,109,787
Amortizations Related to Surcharge Revenues (July 2002 - June 2003)	-$24,546,623
Unrecovered Balance at June 30, 2003	$22,163,392

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 30TH DAY OF SEPTEMBER 2003, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. AVU-E-03-6, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

DAVID J. MEYER
SR VP AND GENERAL COUNSEL
AVISTA CORPORATION
PO BOX 3727
SPOKANE WA 99220-3727

KELLY NORWOOD
VICE PRESIDENT
AVISTA CORPORATION
PO BOX 3727
SPOKANE WA 99220-3727

E-MAILED TO DON FALKNER AT:
dfalkner@avistacorp.com

Glenda D. Koch
SECRETARY

Exhibit No. 139
Case No. AVU-E-04-1/
AVU-G-04-1
K. Hessing, Staff
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AVISTA CORPORATION
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Idaho	DATE PREPARED:	05/10/2004
CASE NO:	AVU-E-04-01 / AVU-G-04-01	WITNESS:	
REQUESTER:	IPUC	RESPONDER:	R. Gruber
TYPE:	Data Request	DEPARTMENT:	Energy Resources
REQUEST NO.:	Staff 27-Supplemental	TELEPHONE:	(509) 495-4001

REQUEST:

Avista has recently relied on financial hedging to provide some level of natural gas price stability. Please provide all data on all hedges executed from 1999 to present. Please provide the analysis that indicates that maintaining this practice is preferred (operationally and/or financially) to reacquiring all of Avista's storage resources.

SUPPLEMENTAL RESPONSE:

Avista's original response inadvertently omitted the data requested on all hedges executed from 1999 to present. A spreadsheet listing all hedges executed by Avista for Washington/Idaho for the period requested is attached. These hedges are all fixed for float swaps and represent only deals done for natural gas utility core load. All of the hedges with transaction dates up to and including May 16, 2001 were executed by the Utility outside of the Benchmark Mechanism. Hedges transacted after that date were executed by Avista Energy on behalf of the Utility as part of the Benchmark Mechanism as modified effective April of 2002.

Avista Corporation
Benchmark Mechanism Evaluation
Natural Gas Prices Fixed for Washington & Idaho

Lock-in Date	Quantity Dth/Day	Term	Basin		Price
12/4/2000	5000	January 2001 through March 2001	Sumas	$	12.6500
12/4/2000	5000	January 2001 through March 2001	Alberta	$	7.2000
12/4/2000	5000	January 2001 through March 2001	Rockies	$	7.4000
12/4/2000	5000	January 2001 through March 2001	Sumas	$	12.6500
12/14/2000	4739	November 2001 through March 2002	Alberta	$	7.25 Cdn
2/5/2001	5000	November 2001 through March 2002	Rockies	$	5.0400
3/7/2001	5000	November 2001 through March 2002	Alberta	$	5.3000
3/7/2001	5000	April 2001 through October 2001	Alberta	$	5.1600
3/7/2001	5000	November 2001 through October 2002	Alberta	$	4.7750
3/7/2001	5000	April 2001 through October 2001	Rockies	$	4.7500
3/7/2001	5000	November 2001 through October 2002	Rockies	$	4.6350
4/23/2001	5000	November 2001 through October 2002	Alberta	$	4.8100
4/23/2001	5000	November 2001 through October 2002	Sumas	$	6.9000
5/2/2001	5000	November 2001 through October 2002	Sumas	$	6.2500
5/8/2001	5000	November 2001 through October 2002	Alberta	$	4.2200
5/15/2001	5000	November 2001 through March 2002	Alberta	$	4.7450
5/15/2001	5000	November 2001 through March 2002	Rockies	$	4.5950
5/16/2001	5000	November 2001 through March 2002	Sumas	$	7.3000
4/4/2002	3000	November 2002 through March 2003	Alberta	$	3.3300
4/4/2002	1000	November 2002 through March 2003	Rockies	$	3.4250
4/4/2002	1000	November 2002 through March 2003	Sumas	$	3.7800
5/22/2002	6000	December 2002 through January 2003	Alberta	$	3.7400
5/22/2002	2000	December 2002 through January 2003	Sumas	$	4.3350
5/22/2002	2000	December 2002 through January 2003	Rockies	$	3.7700
5/30/2002	3000	December 2002 through February 2003	Alberta	$	3.5200
5/30/2002	1000	December 2002 through February 2003	Sumas	$	3.8300
5/30/2002	1000	December 2002 through February 2003	Rockies	$	3.5900
5/30/2002	3000	November 2002 through February 2003	Alberta	$	3.4800
5/30/2002	1000	November 2002 through February 2003	Sumas	$	3.7500
5/30/2002	1000	November 2002 through February 2003	Rockies	$	3.5100
6/13/2002	3000	November 2002 through March 2003	Alberta	$	3.3300
6/13/2002	1000	November 2002 through March 2003	Sumas	$	3.6700
6/13/2002	1000	November 2002 through March 2003	Rockies	$	3.3050
7/12/2002	6000	November 2002 through October 2003	Alberta	$	3.2000
7/12/2002	2000	November 2002 through October 2003	Sumas	$	3.3550
7/12/2002	2000	November 2002 through October 2003	Rockies	$	2.9750
7/14/2002	3000	November 2002 through March 2003	Alberta	$	3.2000
7/14/2002	1000	November 2002 through March 2003	Sumas	$	3.5000
7/14/2002	1000	November 2002 through March 2003	Rockies	$	3.0700
8/29/2002	3000	December 2002 through March 2003	Alberta	$	3.3970
8/29/2002	1000	December 2002 through March 2003	Rockies	$	3.2030
8/29/2002	1000	December 2002 through March 2003	Sumas	$	3.8480
11/7/2002	5890	December 2002 through March 2003	Alberta	$	3.4050
11/7/2002	2010	December 2002 through March 2003	Sumas	$	3.7000
11/7/2002	2010	December 2002 through March 2003	Rockies	$	3.2900
4/15/2003	2745	November 2003 through March 2004	Alberta	$	5.0350
4/15/2003	1005	November 2003 through March 2004	Sumas	$	5.5350
4/15/2003	1250	November 2003 through March 2004	Rockies	$	5.1200
6/13/2003	2010	November 2003 through March 2004	Sumas	$	5.6700
6/13/2003	5490	November 2003 through March 2004	Alberta	$	5.3450
6/13/2003	2500	November 2003 through March 2004	Rockies	$	5.2800
7/14/2003	2745	November 2003 through March 2004	Alberta	$	4.7850
7/14/2003	5490	April 2003 through October 2004	Alberta	$	4.0250
7/14/2003	2010	April 2003 through October 2004	Sumas	$	4.0600
7/14/2003	1005	November 2003 through March 2004	Sumas	$	5.1500
7/14/2003	2500	April 2003 through October 2004	Rockies	$	4.2580
7/14/2003	1250	November 2003 through March 2004	Rockies	$	4.2580
8/22/2003	2745	December 2003 through March 2004	Alberta	$	5.0250
8/22/2003	1250	December 2003 through March 2004	Rockies	$	5.1100
8/22/2003	1005	December 2003 through March 2004	Sumas	$	5.3400
8/14/2003	2745	November 2003 through March 2004	Alberta	$	4.8100
8/14/2003	1250	November 2003 through March 2004	Rockies	$	4.8600
8/14/2003	1005	November 2003 through March 2004	Sumas	$	5.1100
8/22/2003	5490	December 2003 through February 2004	Alberta	$	5.1150
8/22/2003	2500	December 2003 through February 2004	Rockies	$	5.1900
8/22/2003	2010	December 2003 through February 2004	Sumas	$	5.5600
8/22/2003	5490	December 2003 through January 2004	Alberta	$	5.1160
8/22/2003	2500	December 2003 through January 2004	Rockies	$	5.2010
8/22/2003	2010	December 2003 through January 2004	Sumas	$	5.5700
10/20/2003	2010	December 2003 through March 2004	Sumas	$	4.9450
10/20/2003	5490	December 2003 through March 2004	Alberta	$	4.6550
10/20/2003	2500	December 2003 through March 2004	Rockies	$	4.8100
10/31/2003	2500	October 2004	Rockies	$	4.0600
10/31/2003	2010	October 2004	Sumas	$	4.1350
10/31/2003	5490	October 2004	Alberta	$	4.0450
10/31/2003	2500	April 2004	Rockies	$	4.0330
10/31/2003	2010	April 2004	Sumas	$	4.0030
10/31/2003	5490	April 2004	Alberta	$	4.0030
4/14/2004	2500	November 2004 through March 2004	Alberta	$	5.4650
4/14/2004	1250	November 2004 through March 2004	Rockies	$	5.6050
4/14/2004	1250	November 2004 through March 2004	Sumas	$	5.6800

Exhibit No. 140
Case No. AVU-E-04-1/
AVU-G-04-1
K. Hessing, Staff
6/21/04 Page 2 of 2

STAFF EXHIBIT NO. 141 IS CONFIDENTIAL

Exhibit No. 141
Case No. AVU-E-04-1/
AVU-G-04-1
K. Hessing, Staff
6/21/04

Staff Case
Avista Utilities - Electric
State of Idaho
Revenue Allocation
Normalized 12-Months Ending December 31, 2002

Line No	Type of Service	(1) Rate Sch. No.	(2) Average Number of Customers	(3) Sales Normalized (MWh)	(4) Current Revenue*	(5) Proposed General Increase	(6) Proposed PCA Decrease	(7) Proposed DSM Rider Decrease	(8) Net Revenue Adjustments	(9) Proposed Revenue	(10) Average Rate ¢/kWh	(11) Percent Change
1	Residential	1	87,494	988,380	60,102,000	9,878,022	(6,417,940)	(365,701)	3,094,382	63,196,382	6.39	5.1%
2	General Service	11	16,051	225,328	19,436,000	1,845,706	(2,038,828)	(112,664)	(305,786)	19,130,214	8.49	-1.6%
3	Large General Service	21	1,789	674,177	41,682,000	4,472,782	(4,464,139)	(242,704)	(234,060)	41,447,940	6.15	-0.6%
4	Extra Large General Service	25	14	303,707	12,346,000	2,100,012	(1,135,680)	(74,105)	890,227	13,236,227	4.36	7.2%
6	Potlatch	25	1	870,086	33,056,000	4,116,501	(3,409,936)	(212,301)	494,264	33,550,264	3.86	1.5%
7	Pumping Service	31	1,043	48,922	2,997,000	345,126	(262,185)	(18,101)	64,840	3,061,840	6.26	2.2%
8	Street and Area Lights	41-49	-	12,983	2,228,000	320,728	(235,127)	(13,048)	72,553	2,300,553	17.72	3.3%
9	Total/Average			3,123,583	171,847,000	23,078,877	(17,963,835)	(1,038,623)	4,076,419	175,923,419	5.63	2.4%

* Includes all present rate adjustments; Residential Exchange Credit, Centralia Credit, PCA Surcharge, DSM Rider

Exhibit No. 142
Case No. AVU-E-04-1/
AVU-G-04-1
K. Hessing, Staff
6/21/04

U:\khessin\AVUE0401\Staff Case\Staff Calculations 6/17/2004

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 21ST DAY OF JUNE 2004, SERVED THE FOREGOING **EXHIBITS OF KEITH HESSING,** IN CASE NO. AVU-E-04-1/AVU-G-04-1, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

DAVID J. MEYER
SR VP AND GENERAL COUNSEL
AVISTA CORPORATION
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SPOKANE WA 99220-3727

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VICE PRESIDENT – STATE & FED. REG.
AVISTA UTILITIES
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Jo Nelson
SECRETARY