SCOTT WOODBURY
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0320
BAR NO. 1895

Street Address for Express Mail:
472 W. WASHINGTON
BOISE, IDAHO 83702-5983

Attorney for the Commission Staff

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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

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

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

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.

Respectively submitted this 30th day of September 2003.

Scott Woodbury
Deputy Attorney General

Technical Staff: Kathy Stockton
Marilyn Parker
Keith Hessing

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