BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-03-06

DIRECT TESTIMONY OF RICHARD L. STORRO

REPRESENTING AVISTA CORPORATION

Exhibit ___(RLS-T)

Q. Please state your name, employer and business address.

A. My name is Richard L. Storro. My business address is 1411 East Mission Avenue, Spokane, Washington, and I am employed as the Director of Power Supply for Avista Utilities.

Q. What is your educational background?

A. I participated in a program with the College of Idaho and the University of Idaho, where upon completion I received a Bachelor of Science degree in physics from the College of Idaho and a Bachelor of Science degree in electrical engineering from the University of Idaho, both in 1973.

Q. How long have you been employed by the Company?

A. I started working for Avista in 1973 as a distribution engineer. I have worked in various engineering positions, and have held management positions in line and gas operations, system operations, hydro production and construction, and transmission. I joined the Energy Resources Department as a Power Marketer in 1997 and became Director of Power Supply in 2001. My primary responsibilities involve the oversight of both the short-term and long-term planning and acquisition of power supply resources for the Company.

Q. Can you please summarize your testimony?

A. Yes. First I provide a brief summary of the factors driving power supply expenses during the review period, July 2002 through June 2003. I then provide more detail for several specific items. These items include: 1) the Enron long-term contract termination, 2) the Kettle Falls Bi-Fuel lease payments, 3) the delay in the online date of the Coyote Springs 2 project, and 4) the purchase and sale of fixed price natural gas.

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

A. Yes. I am sponsoring Exhibit Nos. ___(RLS-1) and ___(RLS-2), which were prepared under my supervision and direction.

SUMMARY

Q. Would you please summarize the power supply expense deferrals during the review period?

A. Yes. During the review period, Idaho's share of power supply expenses exceeded the authorized level by $25,924,662. Of that total, 90 percent or $23,332,195 was deferred and the Company absorbed 10 percent or $2,592,466.

Power supply expenses were higher than the authorized level due to several factors. The largest factor was the sale of fixed price gas. Based on the average purchase and sale price, the fixed price gas purchases added approximately $13.1 million to Idaho's share of power supply expense. Hydro generation was approximately 12.9 aMW below the authorized level, which would account for approximately $2.1 million of increased expense. Colstrip and Kettle Falls together generated approximately 8 aMW above the authorized. Rathdrum generated approximately 21 aMW below the authorized level due in part to the relatively low price of electricity compared to natural gas costs. The Company' other gas-fired generating plants, Northeast turbine, Boulder Park, and the Kettle Falls combustion turbine generated 2 aMW during the period.

Other power supply expenses during the review period include a payment to terminate a long-term power purchase with Enron and the final lease payments of $3.7 million ($1.3 million Idaho share) related to the Kettle Falls Bi-Fuel generating units. The $2.9 million Enron buyout payment ($960,000 million Idaho share) occurred in

October 2002, and was recorded as a power purchase expense. The Kettle Falls Bi-Fuel lease payments began in September 2001 and were included in the prior filing for the review period ending June 2002.

Another factor driving the deferrals is the age of the authorized case. The authorized case is based on the loads, contracts and resources in place for the period July 1999 through June 2000. During that period, the Company had several large off-system power sales that generated significant revenue. Almost all of those sales have ended and, as such, the revenue is reduced, which is reflected in a reduction in Account 447, Sale for Resale, revenue of $72 million on a system basis ($24 million Idaho share). Purchased power expense has also decreased from the authorized level due in part to several long-term contracts ending. Purchased power expense, however, has decreased by only $24 million on a system basis ($8 million Idaho share). The Company plans to file a general rate case within the next year to reset the authorized level of power supply revenues and expenses.

ENRON CONTRACT SETTLEMENT

Q. Please provide a brief overview of the Enron contract buyout.

A. In 2001 Avista entered into a multi-year power purchase agreement with Enron. After filing for bankruptcy, Enron advised counterparties that they would be willing, in conjunction with the Creditors' Committee, to consider offers of settlement for the outstanding contractual positions. Avista sent an original proposal for the termination of the Enron Purchase that was rejected by Enron's Creditors' Committee. Subsequent discussions between Avista and Enron culminated in the final settlement agreement. The final agreement called for the mark-to-market value of the contract to be determined by a third party market price and discounted by 11.5 percent. The calculation of the payment would be performed based on prices the day prior to the bankruptcy judge approving the settlement.

Q. How did customers benefit from the buyout?

A. Customers benefited in a couple of ways. First, the Company removed the uncertainty of whether or not the energy would be delivered. There was little likelihood that Enron could deliver the energy and if the contract was sold to another counterparty, it would raise additional uncertainties as to who the counterparty would be, and its creditworthiness and ability to deliver power. Second, the customers benefited by the higher discount rate used to value the contract. The discount rate used to determine the buyout amount was 11.5%, which is higher than Avista's discount rate and well above the carrying charge rate on the PCA deferral balance. This higher discount rate resulted in a $218,000 benefit to Idaho customers. The Company also netted against the contract settlement payment approximately $1 million of a net accounts receivable owed to Avista by Enron. These receivables were for transactions that had occurred in 2001, and reflected revenues that the Company had already credited to customers in prior PCA deferral calculations. Therefore, through this buyout, Avista preserved for customers dollar for dollar recovery of these amounts owed to Avista by the bankrupt Enron.

KETTLE FALLS BI-FUEL LEASE PAYMENTS

Q. Please explain the lease payments for the Kettle Falls Bi-Fuel generating units.

A. The Company made lease payments on the Kettle Falls Bi-Fuel generating units from September 2001 through December 2002. An explanation of these leased units, together with supporting workpapers, was provided in the prior August 2002 PCA filing, and a review of these lease payments was conducted in that proceeding. The $1.3 million (Idaho share) of payments during this review period represent the final lease payments.

COYOTE SPRINGS 2

Q. Could you please provide a brief overview of the Coyote Springs 2 project?

A. Yes. The Coyote Springs 2 project began commercial operation on July 1, 2003 and has been operating reliably. The Company's fifty-percent share of the output has been in the 115 to 125 MW range.[1] The plant was originally planned to be on-line June 2002, but several issues beyond the Company's control, including the Enron bankruptcy and problems with the generator step-up transformer caused a delay in the on-line date of the plant.

Q. Please explain the impact of the bankruptcy of Enron and its subsidiary NEPCO on the CS2 project construction schedule.

A. Enron filed for bankruptcy in late 2001. Enron ceased making funds available to NEPCO to pay vendors, equipment suppliers, craft, etc. to complete the CS2 project. In first quarter 2002, the CS2 partners (Avista and Mirant) stepped in and took over the role of CS2 EPC contractor from NEPCO. The transition process included dismissing construction staff at the CS2 site and putting in place new management and

[1] The variation in the output is due primarily to the ambient air temperature, i.e., the warmer the weather, the lower the output, and vice-versa.

construction staffing. The replacement of NEPCO added approximately two months to the project completion timeline, which was extended into August of 2002.

Q. Please explain the delay related to the generator step-up transformer.

A. The completion of the CS2 project was delayed first by a failure of the original generator step-up (GSU) transformer in May of 2002 and second by damage to the replacement GSU transformer that was observed upon its arrival at the project site in December 2002.

Q. Would you please describe the circumstances of the failure of the first GSU transformer?

A. Yes. On March 3, 2002 the GSU transformer was energized from the CS2 switchyard that is interconnected with the Bonneville Power Administration (BPA) 500kV transmission system. The generators at CS2 were not operational during that time frame. On May 6, 2002 the GSU transformer experienced an internal failure, which resulted in significant damage to the transformer windings and a rupture of tank.

Q. What steps did the CS2 partners, Avista Corporation and Mirant, take to address the GSU transformer failure?

A. The CS2 partners investigated options for replacing the GSU transformer including an investigation into whether there was a compatible spare GSU transformer available from another company in the industry. One of the first options investigated was to attempt to find another entity that might have an available three-phase transformer with the same capacity, winding configuration and respective voltage ratings. Alternatively, the CS2 partners looked for combinations of transformers that could be used together to provide the necessary configurations. However, the CS2 partners were unable to locate an unused transformer or transformer combination that would match up with the CS2 GSU transformer specifications.

Other alternatives explored at that time included: 1) repair of the original transformer; 2) purchase of a new second transformer from Alstom; 3) purchase of a new second transformer from a different vendor; 4) change the original design of CS2 to allow for installation of multiple transformers.

Q. Which of the options did the CS2 partners select to address the transformer failure?

A. On June 13, 2002 the CS2 partners decided to purchase a second GSU transformer from Alstom. The deciding factor was the shorter lead-time for a new Alstom transformer compared to a new transformer from an alternate manufacturer. Alstom has over 100 years in the electrical equipment business and is one of the world's leading manufacturers of electric generation, transmission and distribution equipment. They have over 30,000 employees in more than 30 countries. Alstom has been manufacturing transformers up to 525 kV rated voltage and 400 MVA rated power in the Gebze plant for over 30 years.

Q. Will the CS2 partners be compensated for the failed transformer?

A. Work with the insurance company for the CS2 project is in progress. At this time the insurers have indicated that they will pay for the replacement transformer and a portion of the costs to clean up the site due to the oil spill.

Q. Would you please describe the circumstances related to the damage to the second GSU transformer?

A. Yes. The second transformer arrived at the CS2 site on December 15, 2002. After the transformer was moved onto its foundation, Alstom personnel performed an internal inspection and found that the fifth leg of the transformer core had been damaged. Alstom and CS2 representatives discussed the situation and agreed that the second transformer could not be repaired in the field and would need to be sent to a suitable repair facility. Arrangements were made to ship the transformer to the Edison ESI repair facilities in California. The repairs were completed and the transformer was onsite in May 2003. The plant began commercial operation July 1, 2003 and the transformer and the generating plant have been operating reliably.

NATURAL GAS SALES

Q. Please explain the sales related to the fixed price natural gas contracts.

A. In early 2001, the Company purchased approximately 48,000 decatherms per day of index priced gas. Soon afterwards, the Company entered into four fixed-for-floating swaps that fixed the price for a portion of the gas purchases. The gas prices are fixed for 40,000 decatherms per day through October 2003 and for 20,000 decatherms per day through October 2004. The average price of the 40,000 decatherms per day of fixed price gas is $6.14 per decatherm and the average price of the 20,000 per day is $6.30 per decatherm. An explanation of these transactions together with extensive supporting documentation was provided in the prior August 2002 PCA filing, and a review of these transactions was conducted in that proceeding.

Q. This natural gas was purchased for which generating plants?

A. When the Company purchased the gas in early 2001 it was anticipated that most of it would be consumed at Coyote Springs 2, because it is the Company's most efficient gas-fired plant. The deal tickets explaining the fixed-for floating swaps indeed refer to gas purchased for the Coyote Springs plant. It was understood at the time however, that the gas could be consumed at any of the Company's gas-fired plants, including, Rathdrum, Northeast, Boulder Park, the Kettle Falls combustion turbine, and Coyote Springs 2.

The gas was purchased with delivery rights to Malin, Coyote Springs 2 and the Company's other gas-fired plants. The gas could be used at Rathdrum or also be easily be laid off or diverted to the Northeast, Boulder Park and Kettle Falls CT projects. This portfolio of gas-fired plants provides multiple options for Avista. Coyote will normally be operated as a baseload gas-fired resource. If Coyote is unavailable then the gas can be used at any of the Company's other gas-fired projects. If, on the other hand, the price of electricity is less expensive than the cost of running the gas-fired plants, the gas can be sold and electricity purchased.

As previously explained in the August 2002 filing, hedging the price of natural gas was less expensive than purchasing power at the prices in the forward market. The fixed price gas could be used to generate power at the Company's plants for the following cost:

Plant	Generation Cost ($/MWh)
Coyote Springs 2	$45
Boulder Park	$58
Kettle Falls CT	$57
Rathdrum	$75
Northeast	$85

This gas was purchased at a time when the comparable cost for electricity was in the range of $75/MWh to $117/MWh for a flat power product at the Mid Columbia.

While it was assumed at the time that the Company would consume the gas at Coyote Springs, since it would be the Company's most efficient unit, the Company's overall gas management strategy remained the same despite Coyote Springs 2 temporarily not being available.

Q. How does the Company manage natural gas purchased for thermal generation?

A. The overall objective of managing natural gas purchased for generation is to minimize the total power supply expense of the Company. This is done by purchasing the required energy to serve load at the least cost, either by purchasing gas to fuel power plants or by directly purchasing electricity. Natural gas purchased for generation of power is converted to MWh based on the heat rates of the most efficient and economical plants available. On a daily basis, the cost to generate using gas is calculated using the forward value of the gas times the heat rate of the plants plus any variable plant O&M. This cost to generate is then compared to the cost of market electricity for the same forward period. If the cost to purchase market electricity is lower than the cost to generate at the most efficient plants available, then the gas is sold and if needed, the power to replace the lost generation is purchased.

Each day the Company reviews its 18-month forward-looking load and resource monthly imbalance position contained in the daily Position Report and the timing of the purchase or sale of either natural gas or electricity for delivery in various future time frames is evaluated. The Position Report incorporates the most current information on expected future hydroelectric generation levels, thermal generating plant availability and fueled status, and load forecasts. Monthly imbalance positions in the Position Report are differentiated between heavy load hour and light load hour periods. The Company's Risk Policy provides over-arching guidance to this evaluation process with respect to short and long imbalance position limits. The Risk Policy volumetric limits for short and long positions are larger the further one looks into future periods and more narrow in the near-term months. The timing of decisions to purchase or sell either natural gas or electricity in future periods are guided by the Company's Risk Policy and by an assessment of the daily Position Report in combination with the economic evaluation of the relative economic choice between generating with natural gas or purchasing electric power.

In the workpapers included with this filing, the Company has provided detailed information regarding each of the natural gas sales transactions that occurred during the PCA review period. The documentation for each transaction, which was prepared at the time the transaction occurred, generally includes the deal ticket, a brief write-up explaining the reason for the transaction, the daily Position Report showing the Company's load/resource situation for the relevant period, the market prices for electricity and natural gas for the period, as well as other supporting information.

Q. Is natural gas ever sold without purchasing market electricity?

A. Yes, if the Company has a surplus electric power position, selling gas may create greater value than using the gas to generate electricity and selling electric power. If the sale of gas and resulting decrease in generation does not require a purchase of power to balance the forward position, the power would not be purchased.

Q. What was the benefit of selling the gas instead of using it for generation?

A. By selling the gas the Company lowered total power supply expense over the review period. The savings can be calculated by first converting the cost of gas to a cost of generation (including variable plant O&M) at the plants for which generation was displaced. This cost is then compared to an actual purchase cost of power in the same time frame (i.e. peak for August), for equivalent MWh. If it was not necessary to purchase power, due to estimated electric surplus condition, then a quoted price for power at the time of the gas sale was used. An example of how the savings are determined and how the savings are recorded and included in the PCA calculations is shown in Exhibit No. __(RLS-1).

Gas is often sold months ahead of the delivery period. For example on June 20, 2002, gas was sold and power purchased for the months of November and December 2002. Gas volumes of 12,000 dth/day at $3.54/dth for November and 5,000 dth/day at $3.82/dth for December were sold and power (25 MW November flat @ $33.50/MW and 25 MW December LL @ $34.00/MW) was purchased. The estimated benefit of this transaction was about $318,000, as detailed on lines 14 and 15 in Exhibit No. __(RLS-2).

Based on the actual gas sales and power purchases during the review period the Company estimates a reduction in power supply costs of $11.8 million (system basis, $3.9 million Idaho share) for the 40,000 dth/day of fixed priced turbine fuel sold for the July 1, 2002 through June 30, 2003 delivery period. A summary page showing the gas sales and electric purchases that resulted in these savings is shown in Exhibit No. __(RLS-2).

Q. With higher gas prices, will the Company continue to show a cost in the deferrals for the sale of gas not consumed?

A. Yes. The Company may continue to sell gas and purchase power depending on the cost relationship between gas and electricity. In fact, in 2002, the

Company sold some of the fixed price gas that was to be delivered in 2003 and made electric purchases to replace the energy. Because these gas sales were made before the price of gas had risen substantially, the sale of the gas will show a loss. Offsetting that loss, however, are power purchases at relatively low prices compared to current power prices. These transactions reduced overall power supply expenses even though there is an expense for the sale of the gas.

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

A. Yes.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-03-06

EXHIBIT NO. 1 (RLS-1)

NATURAL GAS SALES BENEFIT EXAMPLE

Avista Corp.
Natural Gas Sale Benefit Example

Original Transaction (Early 2001)	
Purchased 10,000 MMBtu/day of Gas at $6/MMBtu	
Total Cost for November 2002	**$1,800,000**
At $6/MMBtu, Rathdrum Generation Cost = $72/MWh	
Economic Benefits of Swap Transaction	
Sold 10,000 MMBtu/day of Gas at $3.50/MMBtu	
Total Gas Sale Revenues for November 2002	$1,050,000
Loss on the Sale of Gas	$750,000
At $3.50/MMBtu, Rathdrum Generation Cost = $42/MWh	
Cost ot Purchase to 60 MW on-peak at $35/MWh	$873,600
Total Gas Loss and Power Cost for November 2002	$1,623,600
Net Economic Benefit of Swap	**$176,400**

Accounting Entries if Gas is Used to Generate		
547 Fuel Consumed	$ 1,800,000	Expense
Net Power Supply Expense	**$ 1,800,000**	
Accounting Entries Under Swap Transaction		
547 Fuel Consumed	$ -	Expense
557 Fuel Purchased (Not Consumed)	$ 1,800,000	Expense
456 Fuel Disposed	$ 1,050,000	Revenue
Loss on Fuel Not Consumed	$ (750,000)	
555 Purchased Power Expense	$ 873,600	Expense
Total Power Supply Expense	**$ 1,623,600**	
Net Power Supply Expense Reduction	**$ 176,400**	

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-03-06

EXHIBIT NO. 2 (RLS-2)

NATURAL GAS SALES SUMMARY

Avista Corp.
Summary of Savings Obtained by Selling Fixed Priced Gas, Jul 2002 - Jun 2003
(40,000 Dth/day sold)

Line No.	Transaction Date	Deal Ticket	Delivery Months	Volume (dth/day)	Price ($/dth)	Power Purchases Related to Sale of Gas	Savings from not Generating
1	08-Jan-02	G0270	Jul	10,000	$2.20	No purchases made related to sale of gas due to position length	$84,308
2	03-Apr-02	G0366	Jul	5,000	$3.35	No purchases made related to sale of gas due to position length	$110,927
3	04-Apr-02	G0370	Nov-Oct 03	5,000	$3.65	No purchases made related to sale of gas due to position length	$1,629,216
4	05-Apr-02	G0372	Nov-Oct 03	5,000	$3.52	No purchases made related to sale of gas due to position length	$1,385,341
5	05-Apr-02	G0373 & 374	Jul	15,000	$3.02	No purchases made related to sale of gas due to position length	$258,318
6	17-May-02	G0432	Jul-Oct	5,000	$3.30	25 aMW Q3 02 @ $39.75/MW DT 2190 & Oct 02 @ $36.75/MW DT 2191	$663,172
	21-May-02	G0439	Aug-Oct	5,000	$3.06	25 aMW Aug 02 @ $39.50/MW DT 2200, Sept 02 @ $39.50/MW DT 2196	$528,362
7						& Oct 02 @ $35.75/MW DT 2195	
8	21-May-02	G0438 & 440	Nov	10,000	$3.65	50 aMW Nov 02 @ $35.83/MW DT 2194 & DT 2195 avg price	$219,948
9	22-May-02	G0444	Sep-Oct	5,000	$3.12	25 aMW Sep 02 @ 37.95 DT 2202 & Oct 02 @ $35.90 DT 2194	$121,568
10	23-May-02	G0446	Oct-Dec	5,000	$3.58	25 aMW Q3 02 @ $38.00 DT 2199	$172,755
11	28-May-02	G0448 & 449	Oct	13,000	$3.03	75 aMW Oct 02 @ $35.00/MW DT 2204, 2205 & 2211 avg price	$73,392
12	05-Jun-02	G0464	Dec	5,000	$3.81	25 aMW Q4 02 LL @ $30.50/MW DT 2217	$65,929
13	19-Jun-02	G0485	July	5,000	$2.63	No purchases made related to sale of gas due to position length	$117,124
14	20-Jun-02	G0488	Dec	5,000	$3.82	25 aMW Dec 02 LL @ $34.00/MW DT 2232	$72,304
15	20-Jun-02	G0489	Nov	12,000	$3.54	25 aMW Nov 02 flat @ $33.50/MW DT 2231	$245,639
16	15-Jul-02	G0509	Sep	22,000	$2.24	50 aMW Sep 02 @ $24.50/MW DT 2246 & DT 2251 avg price	$147,716
17	15-Jul-02	G0510 & 511	Aug	30,000	$2.20	125 aMW Aug 02 @ $21.22/MW DT 2247, 2249, 2250, 2254, 2255 avg pr	$513,189
18	13-Aug-02	G0543	Sep	3,000	$2.55	No purchases made related to sale of gas due to position length	$67,257
19	10-Sep-02	G0604	Oct	4,000	$2.99	25 aMW LL Oct 02 @ $27.75/MW DT 2267	$16,995
20	17-Sep-02	G0624	Dec	11,000	$4.02	No purchases made related to sale of gas due to position length	$193,453
21	01-Oct-02	G0660	Nov	3,000	$3.73	25 aMW Nov 02 @ $34.50/MW DT 2276	$88,829
22	01-Oct-02	G0661	Oct (3-31)	3,000	$3.48	25 aMW Oct 02 (4-31) @ $29.25/MW DT 2276	$103,693
	20-Nov-02	G0741	Dec	5,500	$3.97	25 aMW HL Dec 02 @ $36.60/MW DT 2293 & 25 aMW LL Dec 02 @	$113,425
23						$31.40 DT 2294	
24	18-Jul-02	G0515	Mar-Jun	5,000	$3.39	No purchases made related to sale of gas due to position length	$714,288
25	19-Jul-02	G0516	Apr-Jun	5,000	$3.36	No purchases made related to sale of gas due to position length	$565,174
26	15-Aug-02	G0552	Jan	5,000	$3.80	No purchases made related to sale of gas due to position length	$178,365
27	15-Aug-02	G0553	Feb	5,000	$3.70	No purchases made related to sale of gas due to position length	$147,418
28	15-Aug-02	G0554	Mar	5,000	$3.53	No purchases made related to sale of gas due to position length	$68,051
29	30-Sep-02	G0655	May-Jun	10,000	$3.55	No purchases made related to sale of gas due to position length	$521,647
30	30-Sep-02	G0656	May	10,000	$3.53	No purchases made related to sale of gas due to position length	
31	10-Oct-02	G0680	Feb	3,000	$3.93	No purchases made related to sale of gas due to position length	$67,430
32	10-Oct-02	G0681 & 82	Jan	22,000	$4.02	50 aMW Jan 03 @ $39.10/MWh, DT 2279	$561,825
33	20-Nov-02	G0743	Jan	3,000	$4.11	25 MW HLH Jan 03 @ $39.25/MWh, DT 2295	$88,313
34	23-Dec-02	G0792	Feb	5,000	$4.64	75 MW HLH Feb 03 @ $41.25/MWh, DT 2316 & 2317	$178,272
35	23-Dec-02	G0793	Mar	5,000	$4.47	50 MW HLH Mar 03 @ $41.25/MWh, DT 2314 & 2315	$175,831
36	23-Dec-02	G0794	Apr	5,000	$4.09	2 - 25 MW HLH Apr 03 @ $39.00 & $39.50/MWh, DT 2321 & 2323	$136,243
37	31-Dec-02	G0804	Feb-Apr	5,000	$4.15	25 MW HLH Mar & Apr 03 @ $41.25/MWh, DT 2325	
38						25 MW HLH Mar 03 @ $42.25/MWh, DT 2324	$361,019
39	03-Jan-03	G0810	Feb	5,000	$4.45	75 MW HLH Feb 03 @ $41.25/MWh, DT 2316 & 2317	$151,672
40	06-Jan-03	G0814	Feb	4,000	$4.19	25 MW HLH Feb 03 @ $41.25/MWh, DT 2318	
41						25 MW LLH Feb 03 @ $36.00/MWh, DT 2322	
42	09-Jan-03	G0822	Mar	7,000	$4.37	No purchases made related to sale of gas due to position length	$141,031
43	09-Jan-03	G0823	Jun	5,000	$4.25	No purchases made related to sale of gas due to position length	$237,165
44	10-Jan-03	G0827	Jun	5,000	$4.27	No purchases made related to sale of gas due to position length	$137,286
45	14-Jan-03	G0831	Feb	3,000	$4.50	25 MW HLH Feb 03 @ $42.00/MWh, DT 2329	$10,851
46	16-Jan-03	G0837	Mar	3,000	$5.00	25 MW HLH Mar 03 @ $45.00/MWh, DT 2335	$30,107
47	25-Feb-03	G0859	Apr	10,000	$4.91	50 MW HLH Apr 03 @ $44.18/MWh, DT 2353 & 2355	
						25 MW LLH Apr 03 @ $36.75/MWh, DT 2354	$292,134
48	**Total Savings from Selling Gas**						**$11,756,982**

Exhibit No. ___ (RLS-2)
Case No. AVU-E-______

Storro_2003 PCA Ext_ID_Exh RLS-2.xls