BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-01-11

DIRECT TESTIMONY OF KELLY O. NORWOOD

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Kelly O. Norwood. I am employed by Avista Corporation at 1411 East Mission Avenue, Spokane, Washington.

Q. In what capacity are you employed?

A. I am the Vice President and General Manager of Energy Resources for Avista Utilities. I am currently on temporary assignment to focus on the regulatory treatment of Avista's deferred energy cost balances, the rate-making treatment of new generating resources such as Coyote Springs II and Boulder Park, the development of long-term power cost tracking mechanisms, as well as other power supply and gas supply related regulatory issues. During this assignment, Mr. Lloyd Meyers is responsible for the management of electric and natural gas supply, including resource analysis and planning, resource acquisition, and the dispatch of resources to serve retail and wholesale load obligations.

Q. Please state your educational background and professional experience.

A. I am a graduate of Eastern Washington University with a Bachelor of Arts Degree in Business Administration, majoring in Accounting. I joined the Company in June 1981. Over the past 20 years I have spent approximately nine years in the Rates Department with involvement in cost of service, rate design and revenue requirements. I have spent approximately eleven years in the energy resources department (power supply and natural gas supply) in a variety of roles with involvement in resource planning, system operations, resource analysis, negotiation of power contracts, and risk management. I was appointed Vice President and General Manager of Energy Resources in August 2000.

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

A. My testimony will explain the conditions that have led Avista to request a PCA increase. My testimony will provide an overview of Avista's resource planning and power operations, as well as the current hydroelectric generation and wholesale market conditions. I will explain the impact that the volatile market conditions have had on the Company, as well as steps the Company has taken to deal with the changing market conditions and this year's record low hydroelectric conditions.

I am sponsoring Exhibit No. __ (KON-1) through Exhibit No. __ (KON-5) for identification, which were prepared under my direction.

A table of the contents for my testimony is as follows:

II. AVISTA'S RESOURCE PLANNING AND POWER OPERATIONS

Q. Would you please provide a brief overview of Avista's resource planning and power supply operations?

A. Yes. The Company uses a combination of both owned and contracted resources to serve its retail and wholesale load requirements. Dispatch decisions related to these resources are made within the Energy Resources Department of Avista Utilities. The Department conducts studies on a regular basis to determine the need for capacity and energy resources on both a short-term and long-term basis. The Company enters into short-term wholesale sales and purchases transactions to balance its resources with load requirements. Longer-term resource decisions related to building new resources, upgrades to existing resources, demand-side management (DSM) and long-term contract purchases, are generally made in conjunction with the Company's Integrated Resource Plan (IRP) and RFP processes. The Company, however, is not precluded from acquiring resources outside of an RFP process. Exhibit No. __ (KON-1) provides additional details related to of Avista's resource planning and power operations, as well as a tabulation of its loads and resources for the next ten years.

III. HYDROELECTRIC GENERATION CONDITIONS

Q. Please provide background regarding the streamflow conditions for the Pacific Northwest Region in the year 2001.

A. The Pacific Northwest has been experiencing extremely low streamflow for 2001. One indicator for the region is the streamflow in the Columbia River as measured at The Dalles, for the runoff period January 1 through July 31 of each year. For the period January 1, 2001 through July 31, 2001, the runoff, as forecast by the Northwest River Forecast Center, is expected to be 54.7 million acre-feet. That streamflow forecast is 52% of normal and is the second worst year on record for the years 1928-2000, with the record low flow at The Dalles being 53.36 million acre-feet in 1977. It is important to note that this is only one measuring point for regional streamflow, and it is not necessarily an indication of the streamflow available for Avista's hydroelectric projects.

Q. Specifically, how have the streamflow conditions in 2001 affected the hydroelectric generation available to Avista, and are they more or less severe than for the region?

A. Current estimates show that 2001 will produce the lowest hydroelectric generation output in the 73 years for which records have been kept, for the combination of Avista's owned and contracted hydroelectric generation. Page 1 of Exhibit No. __ (KON-2) includes a chart that shows the monthly deviations for 2001 from the normal level of Avista's hydroelectric generation. This chart also shows the expected generation for Avista under "critical water" conditions, as determined by the Northwest Power Pool hydro regulation study (i.e. the worst water conditions on record). Under normal water conditions, Avista would expect to generate - 554 aMW from its hydroelectric resources (owned and contracted). In a critical water year, Avista would expect hydroelectric generation of approximately 150 aMW below normal. Projections for 2001 are for 360 aMW of hydroelectric generation output, which is 194 aMW below the normal hydroelectric generation level of 554 aMW. This is well below what would be expected for even the worst year in the 73 years in which records have been kept. Page 2 of Exhibit No. __ (KON-2) includes a chart showing the variance in Avista's hydroelectric generation from normal for each calendar year from 1929 through 2001, and illustrates that generation for 2001 is expected to be the lowest on record.

IV. WHOLESALE MARKET CONDITIONS

Q. Please provide an overview of the current wholesale electric market conditions.

A. The Western United States has experienced unprecedented and sustained high wholesale electric short-term market prices and price volatility. Beginning in May 2000, wholesale electric market prices increased dramatically and continued at levels that were unprecedented in the West. Although market prices declined substantially in late May and June 2001, prices continue to remain well above historical prices in the West.

A review of historical short-term market prices on an annual basis, monthly basis, as well as on a day-to-day basis shows the dramatic increase in both the level and volatility of the prices. The price information discussed below is based on the Mid-Columbia Electricity Indexes, as reported by Dow Jones.

Annual Prices: Page 1 of Exhibit No. __ (KON-3) includes a bar chart showing the annual average short-term market prices for 1997 through 2000. The year 2000 was divided into two pieces to show the dramatic rise in prices beginning in May 2000. The average price of power rose from $13 per MWh in 1997 to $168 per MWh in 2000. The average price during the first six months of 2001 was $229/MWh.

Monthly Prices: Page 2 of Exhibit No. __ (KON-3) includes a bar chart of the historical monthly short-term market prices in the Northwest from August 1996 through June 2001. Maximum monthly on-peak prices rose from approximately $19.7 per MWh in 1997, to $47.9 and $44.6 per MWh in 1998 and 1999, respectively. In 2000, the maximum on-peak monthly price was $563.7 per MWh, an increase of nearly thirteen-fold over 1999. Prices in 2001 through June have ranged from $68.8/MWh to $308.7/MWh.

Daily Prices: Daily market prices increased even more dramatically. Page 3 of Exhibit No. __ (KON-3) includes a graph showing daily on-peak and off-peak Mid-Columbia Firm Index prices for 1997 through June 2001. As the graph shows, prices remained fairly modest prior to May 2000, when compared to prices and volatility from May 2000 forward. Daily prices exceeded $3,000/MWh in December 2000.

Real-Time Prices: Real-time (hour-to-hour) pricing also has been very volatile. Dow Jones has collected data for real-time transactions since late 1998. Page 4 of Exhibit No. __ (KON-3) provides real-time daily index prices from January 1999 through June 2001. Real-time prices at the Mid-Columbia prior to May 2000 were well below $100 per MWh. Prices since that time frequently have risen above $200 per MWh. Prices have risen as high as $1,286 per MWh.

Q. How has the volatility of the Northwest electricity marketplace changed?

A. Volatility in the marketplace increased dramatically in 2000. Page 5 of Exhibit No. __ (KON-3) illustrates the dramatic rise in the monthly forward prices, as well as the volatility of those prices. This chart presents the lowest, highest, and last price that each month's forward price traded for between July 1998 and December 2001, as of July 25, 2001. Prior to June 2000, the maximum trading range (difference between the highest price for which the month traded and the lowest price) was less than $50/MWh. The chart shows that price volatility following May 2000 increased dramatically. Many months have a trading range exceeding $200/MWh.

Q. How have the wholesale prices for electricity changed recently?

A. Wholesale prices declined considerably in late May and June. Although part of the decline in prices could be attributed to being at a point in time near the height of the hydroelectric runoff period, together with moderate loads in the region and in California due to moderate temperatures, and lower natural gas prices, those factors probably do not account for the total decline in prices. Other factors such as FERC's June 19, 2001 order, which, among other things, implemented new price mitigation (caps) in the the entire Western market, along with various political and legal pressures related to high wholesale prices are also likely contributors to lower prices.

As we move through the summer months and into the fall and winter months, prices will be dependent on many factors including the ability to meet summer loads in California, uncertainties related to available hydroelectric generation for the next operating year, as well as any change in federal action related to price mitigation.

V. IMPACTS ON THE COMPANY

Q. Please describe the impact of market conditions and low hydroelectric conditions on the Company.

A. Power costs in a general rate case are based on "normal" conditions, including weather-normalized retail loads, normal hydroelectric generation conditions, normal thermal operating conditions, and normal wholesale market price conditions. The Company's existing retail rates include power costs based on the assumption that short-term purchases can be made in the range of <u>$20/Mwh to $25/MWh</u>. Purchases of short-term energy at prices in excess of $200/MWh to meet energy deficiencies have caused a significant increase in power costs to the Company. In addition, Avista is currently experiencing the worst streamflow conditions on record. Although the Company has taken a number of extraordinary measures to avoid purchases from the short-term market, these low streamflow conditions have required the Company to purchase additional energy from the short-term market to replace the lost hydroelectric generation.

The actual PCA balance at June 30, 2001 was $30 million for the Idaho jurisdiction. Current estimates of the PCA balance for the Idaho jurisdiction are $69 million at December 31, 2001, $72 million at the end of 2002, and $88 million at the end of 2003. Page 6 of Exhibit No. __ (KON-3) includes a chart showing the electric PCA deferral balances by month for the Idaho jurisdiction from January 2001 through December 2003. The monthly figures through June 2001 are actuals, and the figures beyond June 2001 are estimates.

The dramatic increase in the PCA balance of $30 million (Idaho jurisdiction) at June 30, 2001 to $72 million (Idaho jurisdiction) at December 31, 2001 is driven primarily by purchases at high prices in the short-term market to cover the deficiencies for July-December caused by the record low streamflow conditions for Avista. The Company chose to cover those deficiencies in advance through short-term fixed-price contracts, among other measures, rather than risk the potential for even higher prices as the summer drew nearer. The decision to cover those deficiencies in advance was based on the recent volatility of market prices, the warnings of impending rolling blackouts in California, the persistent refusal of federal policy-makers to mitigate market prices, and the continuing deterioration of hydroelectric generation conditions. Therefore, the costs included in the PCA deferral estimates for July through December 2001 are costs for which the Company has already made firm contractual commitments.

The Company prepared a variance analysis to estimate the total impact on PCA deferrals from the major components that affect power costs such as hydroelectric conditions and wholesale market prices. The loss of a record 194 aMW of hydroelectric generation during 2001 has resulted in an estimated increase in gross costs to Avista of $290 million on a system basis at the wholesale market prices being experienced by the Company during the year (194 aMW x 8760 hours x average price of $171/MWh = $290 million).

The impact on the Company in prior years from very low hydroelectric conditions ranged from $20 million to $30 million annually, because the wholesale market prices were significantly lower. For illustrative purposes, the Company's hydroelectric generation in 1994 was 128 aMW below normal. The weighted average market price experienced by the Company in 1994 was approximately $22/MWh, which would result in an estimated increase in gross costs to the Company from reduced hydroelectric generation of $25 million on a system basis (128 aMW x 8760 hours x $22/MWh = $25 million).

In addition to the lower hydroelectric conditions, the Company's proforma study (for July 2000 - June 2001) in its last general rate case in Washington showed the Company as a net purchaser of energy from the short-term wholesale market of approximately 90 aMW, under normal hydroelectric conditions, at an average price of $23.45/MWh. The variance analysis shows that the increase in market prices in 2001 for these purchases (approximately $165/MWh vs. $23/MWh) results in a gross increase in costs associated with the 90 aMW of market purchases of approximately $110 million on a system basis. The combination of the hydroelectric impacts and the market purchases for 2001 is a gross increase in costs of approximately $400 million on a system basis. This exceeds Avista's annual gross retail electric revenues on a system basis of approximately $360 million.

The Company has taken a number of measures to mitigate the increased power costs such as increased operation of its thermal resources, locking in fixed-price purchases in the prior year, and aggressively pursuing conservation and load curtailment programs. The benefits from these measures has caused the net increase in the PCA balance during 2001, of approximately $230 million on a system basis, to be well below the gross increase in costs of approximately $400 million discussed above. I will discuss these measures in more detail later in my testimony. The costs associated with the hydroelectric conditions and wholesale market prices (costs beyond the Company's control), however, have overwhelmed the benefits these measures have provided, and have required to Company to seek immediate rate relief to address recovery of the net increase in costs.

Furthermore, as mentioned earlier, wholesale prices have decreased dramatically since the later part of May 2001. The substantial decline in forward market prices has reduced the value of future surplus energy on Avista's system for 2002 and 2003 that could be used to offset the increased power costs experienced by the Company in 2001. Therefore, it no longer appears possible to offset the deferred power costs through the value of future surplus energy sales.

Q. Did the Company expect federal regulators to put in place the price mitigation measures ordered on June 19, 2001?

A. No. Industry publications through the May and June time period cite statements by the President and his administration in opposition to caps on power prices in the West. A quote from President Bush in the May 31, 2001 "Megawatt Daily" states, "We will not take any action that makes California's problems worse, and that's why I oppose price caps." In addition, President Bush was quoted as saying, "Price caps do nothing to reduce demand, and they do nothing to increase supply. This is not only my administration's position, this was the position of the prior administration."

As late as June 14, 2001, Megawatt Daily stated that Vice President Cheney and FERC Chairman Curt Hebert "both pledged to stay the course when it comes to energy policy." Megawatt Daily further states that "Cheney and Hebert emphasized the importance of market remedies – and reaffirmed their opposition to price controls. Hebert, for one, was adamant that recent FERC measures would suffice to create a better-functioning market out West." Copies of excerpts from these publications are attached as pages 1-3, of Exhibit No. __ (KON-4).

Q. The FERC has ordered an expedited fact-finding hearing to calculate refunds for spot market purchases in California. The FERC has also ordered an evidentiary proceeding to discuss refunds for the Pacific Northwest. How might FERC ordered refunds affect the power costs incurred by the Company?

A. The Company plans to participate in the proceedings related to refunds. If the FERC ultimately orders and implements refunds, any benefits received or costs incurred by

Avista would be credited or charged against the PCA account balance. If the result is a positive net benefit, then the PCA increase would end sooner.

However, the potential for FERC ordered refunds does not affect the facts underlying this filing and the need for immediate relief. The issues surrounding potential refunds are complex and far from resolved. The FERC proceedings that are currently ordered will take time to work through. Avista cannot count on a refund at this time, and even if it could, it would not occur soon enough or be large enough to address the financial challenges facing the Company.

VI. STEPS TAKEN BY AVISTA TO MITIGATE IMPACTS

Q. Please explain the measures taken by the Company to mitigate the increased costs to the Company from the record low hydroelectric generation conditions and high wholesale market prices.

A. During the first half of 2001 Avista's hydroelectric generation forecasts continued to decline significantly, forward market prices continued to climb, California warned of a large number of potential rolling black-outs for the upcoming summer, and federal policy-makers in Washington D.C. were persistent that price caps would not be imposed as a solution to the high market prices in the West. Under these circumstances, the Company implemented a variety of measures all aimed at mitigating the Company's price exposure in the face of very high and volatile power prices in the forward market.

The Company took a multi-pronged or portfolio approach that included acquiring both demand-side and supply-side resources to cover its energy deficiencies. As stated earlier, given the high prices in the market and the high market volatility, the Company chose to cover its deficiencies in advance rather than risk the potential for even higher prices as the summer drew nearer. Northwest market prices in December 2000 for daily purchases traded as high as $5,000/MWh, as shown in an excerpt from the December 11, 2000 Megawatt Daily, attached as page 4 of Exhibit No. __ (KON-4). Page 5 of Exhibit No. __ (KON-4) includes an excerpt from the same report and states that "balance-of-the-month sold for $2,000 at Mid-C and January there sold for $800 for a third consecutive day." Thus, in light of the volatility of market prices, the warnings of impending summer rolling blackouts in California, and the persistent refusal of federal policy-makers to mitigate market prices, the Company believed that it was imperative to cover the upcoming energy deficiencies in the spring and summer months caused by the continued deterioration of hydroelectric generation conditions.

The measures taken by the Company to cover its deficiencies and mitigate increased costs included the following:

1) Communication of market conditions and conservation messages to customers;
2) Retail Buy-Back Tariffs;
3) Locked in short-term fixed price contract purchases in 2000 for the 2001 year;
4) Filed for a modification of the Company's permit to allow for additional hours of operation for the Rathdrum combustion turbines and locked in fixed prices for natural gas purchases through December 2001;
5) Delayed delivery of a BPA call on exchange power under the WNP#3 settlement agreement from Q1 of 2001 to Q4 of 2001;
6) Exercised energy storage opportunities;
7) Gained permission for increased operation of Northeast Combustion Turbines;
8) Purchased emissions equipment for Northeast to increase available generating hours;
9) Acquired small generation resources;
10) Acquired resources under the RFP process.

1) Communication of Market Conditions and Conservation Messages

Q. How has the Company communicated the present market conditions and the need to conserve to its customers?

A. The Company has communicated the present challenges facing the electric utility industry to its customers through bill inserts, advertisements in the local newspaper, radio and TV media beginning in December 2000. Many advertisements have been run in several different media including direct mail, customer education programs, radio, TV, and print. In a mid-June survey, 87% of Avista customers recalled seeing Company advertising specifically about conservation, and 73% of those customers say they have taken some action to reduce energy use as a result of the advertising messages.

Q. Has the Company seen a noticeable reduction in retail loads?

A. Yes, loads through June 2001 are 20 aMW below the loads authorized in the Company's last general rate case, and 53 aMW below the loads forecasted by the Company for the same period (actual January-June = 977 aMW; Forecast = 1030 aMW). The reduction in loads has reduced the amount of energy that Avista would otherwise have to purchase from the short-term market. The estimated power cost savings during 2001 from the load reductions reduced the PCA by approximately $18.1 million on a system basis.

2) Retail Buy-Back Tariffs

Q. Please explain the "buy-back" programs to encourage a reduction of load requirements.

A. The Company received approval from the Commission to implement three "buy-back" programs.

Industrial Buy-Back Program:

On December 12, 2000, the IPUC approved Avista's request to implement a "buy-back" tariff, sheet no. 70Q, Rule 26, that would allow the Company to pay its Schedule 25 large-load customers to curtail all, or a portion, of its load (Case No. AVU-E-00-10). Under the high market price conditions, the payment to customers to reduce load was adjusted periodically so that it would be less costly than purchasing the same amount of energy from the wholesale market. Curtailment of load under the tariff would provide benefits to the specific customer reducing their load, as well as all other customers of the Company, because the "buy-back" tariff provides a lower-cost means to serve other load requirements than purchasing additional energy in the wholesale market.

The tariff was effective December 12, 2000. Ten customer agreements were executed yielding a savings of approximately 5,600 MWh (system) at a cost of $495,619.

Irrigation Buy-Back Program:

On March 1, 2001 Avista filed a request with the IPUC (Case No. AVU-E-01-4) for approval of a similar "buy-back" tariff (Tariff 70-R) for its Pumping Service customers under tariff Schedules 31 and 32. Many of these customers use a substantial amount of their annual usage during the June through September period. Given the expected low streamflow conditions in the Northwest, and the expected tight electric supply conditions throughout the West during the coming summer months, curtailment of these loads, primarily irrigation loads, would benefit all of Avista's customers, as well as the region as a whole. Savings are paid at the end of the program after results are measured through October 31, 2001. The estimated savings from the 35 customers participating is 5,000 MWh (system) at a cost of $500,000.

<u>"All-Customer" Buy-Back Program:</u>

Under the Company's "buy-back" tariff Schedule 92, Avista will pay participating customers up to 5 cents/KWh (or $50/MWh) for the curtailment of energy. The Commission approved this tariff schedule to be effective May 15, 2001 (Case No. AVU-E-01-6). The Company has saved approximately 30,000 MWh (system) through July 20, 2001 at a cost of approximately $3.1 million.

3) Short-term Fixed Price Electricity Purchases for 2001

Q. Please explain the forward electricity purchases made in 2000 by the Company for 2001.

A. The Company aggressively purchased forward electricity contracts beginning in the fall and through the end of 2000 to serve load obligations in 2001. The purchases were made to reduce the exposure to further increases in short-term market prices. The purchases covered the forecasted deficits for all of 2001, and placed the Company in a slightly surplus condition under normal streamflow conditions and normal thermal operations.

In total, 110 aMW of purchases were made in 2000 (by December 31, 2000) for 2001 with an average cost of $118/MWh. These purchases were made from the short-term market. Purchases were made on a quarterly, monthly and annual basis for either Heavy Load Hours, Light Load Hours or Flat purchases in accordance with what would best fit the shape of the resource requirement that was projected.

4) Permit Modification For Rathdrum and 2001 Forward Natural Gas Purchases

Q. Please explain the Rathdrum operating permit modifications for which the Company applied.

A. The Company currently can operate the two Rathdrum units a total of 6600 hours per unit per year. Because of the high electric market prices, the Company filed to extend the hours of operation for Rathdrum to 8242 hours per unit per year. Otherwise, Avista would have to shut the units down once the operating hour limit was reached. During the first half of 2001, the Company proceeded to operate Rathdrum at full load in anticipation of receiving the permit modification. Running the units at full load avoided making additional expensive purchases from the wholesale market. If the permit were delayed or denied, the plant would have to be shut down sometime in the September/October time frame which would result in increased costs to the Company, and an increase in the PCA balance. Public hearings have been held on the request for additional operating hours and the Company is still waiting for the Idaho Department of Environmental Quality's determination.

Q. Please explain the purchase of natural gas for the Rathdrum turbines for 2001.

A. The Company made forward natural gas purchases at fixed prices in sufficient quantities to operate its Rathdrum turbines during 2001. The increased operation of Rathdrum to cover hydroelectric generation deficiencies has reduced the PCA balance. The natural gas purchases were made as part of the portfolio approach to mitigating the overall costs to cover energy deficiencies. Fixing the price for these gas purchases limited the exposure to higher prices for this portion of the portfolio.

5) Delayed Delivery of BPA Call On Exchange Power Under The WNP#3 Settlement Agreement

Q. Please explain the benefit of delaying delivery of Bonneville Power Administration's call on exchange power under the WNP#3 Settlement Agreement.

A. In the winter of 2000, BPA notified Avista that it would be exercising a provision in the WNP#3 Settlement Agreement that had not been used before. This provision allows BPA to request energy during certain months of the year based on the operating costs of the Northeast Combustion Turbine. BPA made a request for 212,714 MWh during the months of January, February, March, April and June of 2001. Through negotiations, BPA agreed on a transaction which delayed the delivery of the energy and relieved Avista of further obligation under the agreement for the 2000/2001 operating year. As part of the transaction, Avista will sell to BPA 100 MW for all hours in the fourth quarter (Q4) of 2001. At the time of the transaction, the benefit from delaying the deliveries was estimated at $6.1 million.

This type of transaction is another example of the portfolio approach to dealing with the extraordinary circumstances faced by the Company in the past year. Delaying delivery of the power to a later date allowed the opportunity for an improvement in conditions to occur that would benefit the Company and its customers. In this particular case, the substantial drop in market prices has caused the cost to Avista to deliver this energy to be substantially lower than the estimated cost at the time the transaction was executed, and has resulted in lower deferred power costs than would have otherwise occurred.

6) Energy Storage Opportunities Exercised by Avista

Q. Please explain the benefits gained by the Company through storage opportunities.

A. Avista took advantage of its rights under the Pacific Northwest Coordination Agreement to store energy in the federal hydro system through the Bonneville Power Administration. Recalling the energy during periods when market prices were very high allowed Avista to optimize its own resources more effectively by taking advantage of the hourly scheduling flexibility of the energy returns. For example, in December 2000, Avista stored energy in BPA's system when weather forecasts indicated extreme cold weather was approaching. Avista was then able to recall the energy to meet load obligations during a time when the market prices were very high. The stored energy also allows Avista to refill its reservoirs following a cold weather event that would cause the Company to draw down its reservoirs to meet load. The benefits from these storage transactions have been credited to customers through the PCA mechanism.

7) Permission for Increased Operation of Northeast Combustion Turbines

Q. Please explain the opportunity for the Company to run the Northeast Combustion Turbines additional hours.

A. Under the existing air emission permit for the Northeast Combustion Turbine, the generation units are allowed to run approximately 500 hours per year. On February 21, 2001 the Company signed an agreement with the Spokane County Air Pollution Control Authority (SCAPCA) that allowed Avista to operate the Northeast turbines for an additional 90 day period beginning February 21st and ending May 22, 2001 and then further extended to May 31, 2001. The agreement involved negotiations with Governor Locke's office, SCAPCA and the federal Environmental Protection Agency. The agreement provided approximately 60 aMW per month for the three-month period, which was estimated to reduce net power costs for Avista's customers by approximately $24.2 million on a system basis compared to the alternative of power purchases at market prices available at the time. These benefits were credited to Avista's customers through the existing PCA mechanism.

As part of the agreement, Avista agreed to develop an "environmental offset project" to achieve future emission reductions in Spokane's federally designated non-attainment areas. Avista agreed to fund the cost of the offset project, up to a total cost of $900,000. In addition, the agreement provides for an additional contribution to low-income energy assistance funds in Avista's service area of approximately $300,000. These costs are also included in the PCA entries along with the benefits associated with running Northeast the additional hours.

An extension of this agreement was negotiated allowing Northeast to continue operation under the Governor's Energy Supply Alert. The extension provided for continuous operation of Northeast beginning May 31, 2001 and continuing through the end of the Governor's Energy Supply Alert or when the new pollution control equipment, as discussed below, becomes operational on Northeast Combustion Turbines. As part of the extension agreement, Avista agreed to pay a mitigation fee of $150 per hour of operation to fund low-income energy assistance and environmental projects designated by SCAPCA. Additionally, Avista will set aside $10,000 for each day of operation of the turbines at Northeast to continue to fund an environmental offset project as described above. By implementing this generation alternative, flexibility was also increased, compared to a purchase of power from the market, allowing the Company the option to dispatch or not run the units if market prices became a lower cost alternative than the variable costs to operate, which has been the case recently.

8) New Emissions Equipment for Northeast Combustion Turbines

Q. Please explain the purchase of new air emissions equipment for its Northeast combustion turbine facility?

A. Company engineers in late 2000 identified a means to reduce emissions from the plant and increase operating hours from 500 hours annually to 3,000 hours of full operation. The new equipment has been ordered and final installation is scheduled for completion during the third quarter of this year. The Company's commitment to the installation of the new pollution control equipment was also a key part of the negotiations with the various parties to allow Northeast to operate additional hours in 2001, as explained above.

Q. What is the expected benefit of increasing the operational hours of the Northeast Combustion Turbine?

A. Investing the approximately $3 million for new pollution control equipment for Northeast provides a very low cost option to generate power at the marginal operating cost of the unit. The marginal cost of this option is less than $5.00/MWh. While currently there is no market offering for call options due to the high volatility of energy prices, this is a very low premium to pay for a strike price at the variable operating cost of the unit. If one uses a $4.00/MMBTU cost for natural gas, the variable operating cost of this unit is approximately $57/MWh.

9) Small Generation Resources

Q. Please explain the acquisition of small generation resources by the Company.

A. The installation of small generation projects distributed on Avista's electrical grid is another component of the portfolio of resources to cover load requirements and mitigate costs. These projects are being installed to cover short-falls in the Company's load and resource position caused by load variations, unscheduled generation outages, variability of hydroelectric generation, etc. Five projects and sites were selected for 85 MW of generation that could be installed relatively quickly, that would have full pollution control equipment, and would run on natural gas, diesel fuel, or a combination of the two. The units include a combination of short-term leased units, which are planned to be removed in mid-2002 when Coyote Springs II is scheduled to be on-line, and long-term ownership.

Because these projects have a fixed and variable cost component, they are similar to purchasing a call option. Call options in the market have been either non-existent or extremely expensive. These units are dispatchable and do not have to run if purchasing energy in the market is less costly. Therefore, these units provided an opportunity to avoid purchasing additional energy from the market at the time. After forward market prices declined substantially, the Company elected to cancel the Othello diesel-fired turbine project. The four remaining projects total 62 MW of capacity. Two of the projects, Boulder Park and Spokane Industrial Park, will be long-term installations consisting of eight natural gas peaking units with a combined capacity of 32 MW.

10) Resource Acquisitions Under the RFP Process

Q. Please explain the Company's recent decision to acquire resources under its Request for Proposals (RFP) process.

A. In the summer of 2000, Avista issued an RFP for approximately 300 MW of supply. In total, 4,400 MW were submitted by 23 parties. On the supply side, the Company received proposals for market-supplied power, natural gas turbines, wind power, and small hydroelectric power. Through an evaluation process the Company determined the Coyote Springs II combined-cycle combustion turbine project located in Boardman, Oregon to be the best option. The plant is currently under construction and is scheduled for an online date of June 2002. The addition of Coyote Springs II in mid-2002 will place Avista in a surplus condition for 2002 and 2003, which will eliminate most of the Company's exposure to the volatility of the market during this period.

In addition to the supply side, DSM resources were evaluated on a separate but parallel path to the supply-side resources. In total the Company anticipates the potential to acquire 13 aMW of additional DSM resources from three suppliers over three years.

VII. PCA MECHANISM

Q. Please briefly summarize the PCA mechanism.

A. The Company's Idaho PCA mechanism tracks 90% of the difference between actual net power supply expense and the authorized level of net power supply expense approved in the last general rate case. The Company's shareholders absorb the remaining 10% of the difference in net power costs. Net power supply expense is the total of purchased power expense plus fuel costs minus wholesale revenues. An overview of the PCA mechanism methodology and calculations are presented in Exhibit No. __ (KON-5).

VII. BPA RESIDENTIAL EXCHANGE BENEFITS

Q. Please explain the expected benefits of the BPA Residential Exchange Settlement

A. In its Settlement Agreement with the Bonneville Power Administration (BPA), Avista received rights to 90 aMW of benefits from the federal hydropower system beginning October 1, 2001. The benefits related to this Settlement are to be shared among Avista's residential and small farm customers.

Avista estimates that the total benefits from the Residential Exchange Settlement in the first year of the Exchange period, which begins October 2001, will be approximately $6.1 million for the Idaho jurisdiction. Mr. Hirschkorn discusses the estimated decrease in rates to the Company's residential and small farm customers later this year related to these benefits.

Q. Does that conclude your testimony?

A. Yes it does.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-01-11

EXHIBIT NO. __ (KON-1)

AVISTA'S RESOURCE PLANNING AND POWER OPERATIONS

Company-Owned Resources

The Company owns and operates two hydroelectric projects on the Clark Fork River in Western Montana and Northern Idaho, and six hydroelectric projects on the Spokane River. These projects are listed below along with the number of generating units at each project, the dependable capacity of each project, and the estimated amount of energy from each project under both average (normal) streamflow conditions and "critical" streamflow conditions, as determined in the latest Northwest Power Pool Regulation Study (2000-01).

Hydroelectric Projects Summary

Generating Project	Units	Dependable Capacity (MW)	Average Energy[1] Average Water (aMW)	Average Energy[1] Critical Water (aMW)
Clark Fork River				
Noxon Rapids	5	554	203	128
Cabinet Gorge	4	236	122	87
Subtotal	*9*	*790*	*325*	*215*
Spokane River				
Post Falls	6	16	10	7
Upper Falls	1	10	9	8
Monroe Street	1	15	13	12
Nine Mile	4	26	16	13
Long Lake	4	84	52	42
Little Falls	4	36	23	19
Subtotal	*20*	*187*	*123*	*101*
Total Hydro	**29**	**977**	**448**	**316**

[1] Based on NWPP 2001 60-year (1928-88) study

In addition, the Company owns and leases the following thermal generating projects:

Thermal Projects Summary

Generating Project	Units	Primary Fuel	Capacity (MW)	Energy (aMW)
Colstrip[2]	2	Coal	222	191
Kettle Falls[3]	1	Woodwaste	49	45
Rathdrum[4]	2	Gas	176	61
Northeast[5]	2	Gas	69	10
Coyote Springs II[6]	1	Gas	280	241
Total Thermal	**8**		**796**	**621**

Retail Electric Load Forecast

Each year the Company prepares a five-year and ten-year electric retail load forecast. The forecasts include the Company's needs for both energy and capacity to serve retail load requirements. In developing the five-year forecast, the Company uses econometric models to produce kilowatt-hour sales and customer forecasts. The econometric models are systems of algebraic equations that relate past economic growth and development in the geographic communities, with the past customer growth and power consumption in those same communities. Each year the forecast incorporates

[2] Avista owns 15% of Units 3 and 4 which are operated by PP&L Montana.
[3] Kettle Falls is owned and operated by Avista Utilities.
[4] Rathdrum was constructed by Avista, but is leased through a sale and lease-back arrangement. Avista operates the project. Air emission restrictions currently limit each unit's operation to 6,600 hours per year per unit.
[5] Northeast is owned and operated by Avista. Air emission restrictions currently limit operation to 500 hours per year per unit. New pollution control equipment has been purchased that will increase the number of hours to 3000 per year per unit. The new equipment is planned to be installed by the third quarter 2001.
[6] Construction began on the Coyote Springs II combined-cycle combustion turbine project in January 2001 and is expected to be completed by June 1, 2002.

changes that occur in the regional and national economy which affect the Company, such as industrial activity, residential use, population growth and income levels.

This five-year forecast is extended for an additional five years, for longer-term resource planning purposes, based on the methodologies and equations described above for its annual five-year forecast.

The forecasted annual capacity and energy figures for years 2001 through 2010 are shown on line 1 on page 7 of this exhibit. The forecast shows an annual average energy load of 1,027 aMW in 2001. The Company's retail load is forecasted to be 1,247 aMW in 2010, a compound growth rate of 2.2 percent per year.

The capacity forecast shows 1,610 MW in 2001, increasing to 1,973 MW in 2010, a compound growth rate of 2.3 percent per year.

The Company's retail energy loads grew from 838 aMW in 1991 to 1,066 aMW in 2000, a compound annual growth rate of 2.7 percent. The Company's retail capacity loads grew from 1,479 MW in 1991 to 1,616 MW in 2000. The compound annual growth rate was 1.0 percent.[7]

Long-Term Loads and Resources Picture

The table on page 7 of this exhibit includes a tabulation of Avista's Requirements and Resources (Load and Resource, or L&R Tabulation) on an annual basis for the next ten years.

The "Peak" columns include peak load "Requirements" in January of each year, the highest one-hour forecasted capacity requirement in each of the years. The

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[7] These figures represent the actual loads experienced by the Company and reflect the actual temperatures that occurred during each of the respective periods, which would affect the calculated annual growth rate.

"Resource" peak numbers represent the maximum capacity output available from the Company's resources to serve the one-hour peak. The "Avg" columns in the table include the expected average energy for the twelve-month period for both loads and resources.

The Company's load requirements are shown on lines 1-16. These load requirements include the Company's retail native load shown on line 1, long-term firm wholesale contract obligations on lines 2-14, and Capacity Reserves on line 15.

Resources available to the Company are shown on lines 17-41. The Company's owned hydroelectric generation on the Clark Fork and Spokane Rivers is included on line 17. The "Contract Hydro" on line 18 includes the contracts Avista has with Douglas, Chelan and Grant County PUDs for a portion of the output from the Wells, Rocky Reach, Wanapum and Priest Rapids hydroelectric projects on the middle section of the Columbia River (Mid-Columbia projects).

Lines 19 - 40 include power available to the Company from long-term firm contract rights and the Company's thermal generating resources. Short-term market purchases made by the Company for 2001 are shown on line 41. A comparison of the total resources with the total system requirements yields the surplus or deficiency on an annual basis. These values are shown on line 43.

The "System Hydro" and "Contract Hydro" figures in the L&R Tabulation reflect energy that could be produced under "critical" water conditions, as determined by the Northwest Power Pool hydroelectric regulation model. The NWPP currently uses the eight-month period September 1936 through April 1937 to represent the "critical period."

The critical period includes the lowest level of available hydroelectric generation for a one-year period during the 1928-1988 study period.

The L&R Tabulation includes an analysis of firm energy loads and resources. The Company use critical water conditions in its L&R Tabulation because energy produced by the hydroelectric system under critical water conditions is considered firm energy, because it represents the amount of energy that can be depended upon, even under what has historically been the most adverse streamflow conditions.

The capacity tabulation provides a view of the Company's forecasted peak loads and peak resources, including capacity reserves. It indicates the maximum hourly load, and the resources available to the Company to meet that load on a firm basis. Values are presented for the month of January, since this is the month during which the Company forecasts its peak to occur. Thermal and hydroelectric resource capabilities are based on their "dependable capacity". Contracts include the peak capability identified within them.

Reserves, as shown on line 15 of the L&R Tabulation, play an integral part in maintaining system reliability to serve firm loads. The planning reserves shown on this tabulation are carried to provide the Company with adequate generating capacity during periods of extreme weather or unexpected plant outages. Included in the reserves component are capacity to meet the contingencies of temperature affects on retail load (cold and hot weather), generator-forced outages, and possible river freeze-up at our hydroelectric plants. The Company plans for reserves in an amount equal to ten percent of firm peak loads, plus ninety additional megawatts to account for river freeze-ups and forced outages. On a day-to-day operating basis, the Company is required by the

Western System Coordinating Council (WSCC) to carry operating reserves equal to 7% of the Company's online thermal resources and 5% of its online hydroelectric resources. Planning for reserves in the long-term L&R Tabulation provides the Company with the necessary operating reserves over time.

The L&R Tabulation provides an indication of the Company's need for firm capacity and energy resources over the ten-year forecast period. The L&R Tabulation on page 7 includes the following surpluses and deficiencies for the respective years:

	Surplus/(Deficiency)	
Year	Capacity MW	Energy aMW
2001	(11)	(118)
2002	73	16
2003	329	138
2004	51	(35)
2005	(56)	(80)
2006	(156)	(97)
2007	(110)	(54)
2008	(168)	(88)
2009	(230)	(128)
2010	(358)	(193)

The results show an energy deficit condition in 2001 and in 2004 and beyond. The study shows a need for capacity beginning in 2005.

Exhibit ___
Critical Water Loads and Resources 2001-2010
All Values in Megawatts

Line No.		2001 Peak	2001 Avg	2002 Peak	2002 Avg	2003 Peak	2003 Avg	2004 Peak	2004 Avg	2005 Peak	2005 Avg	2006 Peak	2006 Avg	2007 Peak	2007 Avg	2008 Peak	2008 Avg	2009 Peak	2009 Avg	2010 Peak	2010 Avg
	REQUIREMENTS																				
1	Retail Load	1,610	1,027	1,554	974	1,605	1,006	1,662	1,046	1,713	1,084	1,755	1,111	1,806	1,142	1,859	1,176	1,915	1,210	1,973	1,247
2	PacifiCorp Exchange	0	3	0	3	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Puget Sound Energy	67	50	33	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	PacifiCorp	0	9	0	9	0	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	PGE Capacity Sale	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0
6	Snohomish PUD	100	75	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Cogentrix	100	75	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Nichols Pumping	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	PGE Energy Sale	25	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Montana Sale	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Duke Sale	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Clark PUD	250	85	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	City of Cheney	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Canadian Entitlement Return	10	5	8	4	8	5	11	6	12	6	8	4	8	4	8	4	8	4	4	2
15	Reserves	251	0	245	0	251	0	256	0	261	0	266	0	271	0	276	0	282	0	287	0
16	TOTAL REQUIREMENTS	2,765	1,476	1,990	1,015	2,014	1,023	2,079	1,052	2,136	1,090	2,179	1,115	2,235	1,146	2,293	1,180	2,355	1,214	2,414	1,249
	RESOURCES																				
17	System Hydro	946	316	946	316	946	316	946	316	946	316	946	316	946	316	946	316	946	316	946	316
18	Contract Hydro	195	79	195	79	195	79	195	79	195	76	140	58	140	58	140	58	140	52	72	22
19	Small Power	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11
20	Cogeneration	59	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Northeast CTs	69	6	69	10	69	10	69	10	69	10	69	10	69	10	69	10	69	10	69	10
22	Rathdrum CTs	176	61	176	61	176	61	176	61	176	61	176	61	176	61	176	61	176	61	176	61
23	PacifiCorp Exchange	50	3	50	3	50	3	50	3	0	0	0	0	0	0	0	0	0	0	0	0
24	Entitlement & Supplemental	4	0	4	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	BPA Res. Exchange	0	12	49	49	49	49	49	49	49	49	47	74	149	149	149	149	149	149	149	149
26	BPA-WNP #3	82	10	82	10	82	10	82	10	82	10	82	10	82	10	82	10	82	10	82	10
27	CSPE	9	5	9	5	8	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	TransAlta-Centralia	200	143	200	143	200	143	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Kettle Falls	49	45	49	45	49	45	49	45	49	45	49	45	49	45	49	45	49	45	49	45
30	Colstrip	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191
31	Coyote Springs II	0	0	0	101	280	241	280	241	280	241	280	241	280	241	280	241	280	241	280	241
32	SEMPRA	0	19	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	BPA 5 yr. Purchase	115	86	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Idaho Purchase	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Duke Purchase	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	MIECO	25	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Cinergy Services, Inc.	0	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Energy Services, Inc.	0	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	Enron	50	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Duke Capacity Purchase	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41	Short-Term Purchases	241	110	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	TOTAL RESOURCES	2,754	1,358	2,063	1,031	2,342	1,161	2,130	1,017	2,080	1,010	2,023	1,018	2,125	1,092	2,125	1,092	2,125	1,086	2,057	1,056
43	**SURPLUS (DEFICIT)**	**(11)**	**(118)**	**73**	**16**	**329**	**138**	**51**	**(35)**	**(56)**	**(80)**	**(156)**	**(97)**	**(110)**	**(54)**	**(168)**	**(88)**	**(230)**	**(128)**	**(358)**	**(193)**

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-01-11

EXHIBIT NO. __ (KON-2)

AVISTA UTILITIES

2001 Avista System and Mid-Columbia Hydro Generation vs. "Critical Water"

(aMW by Month)

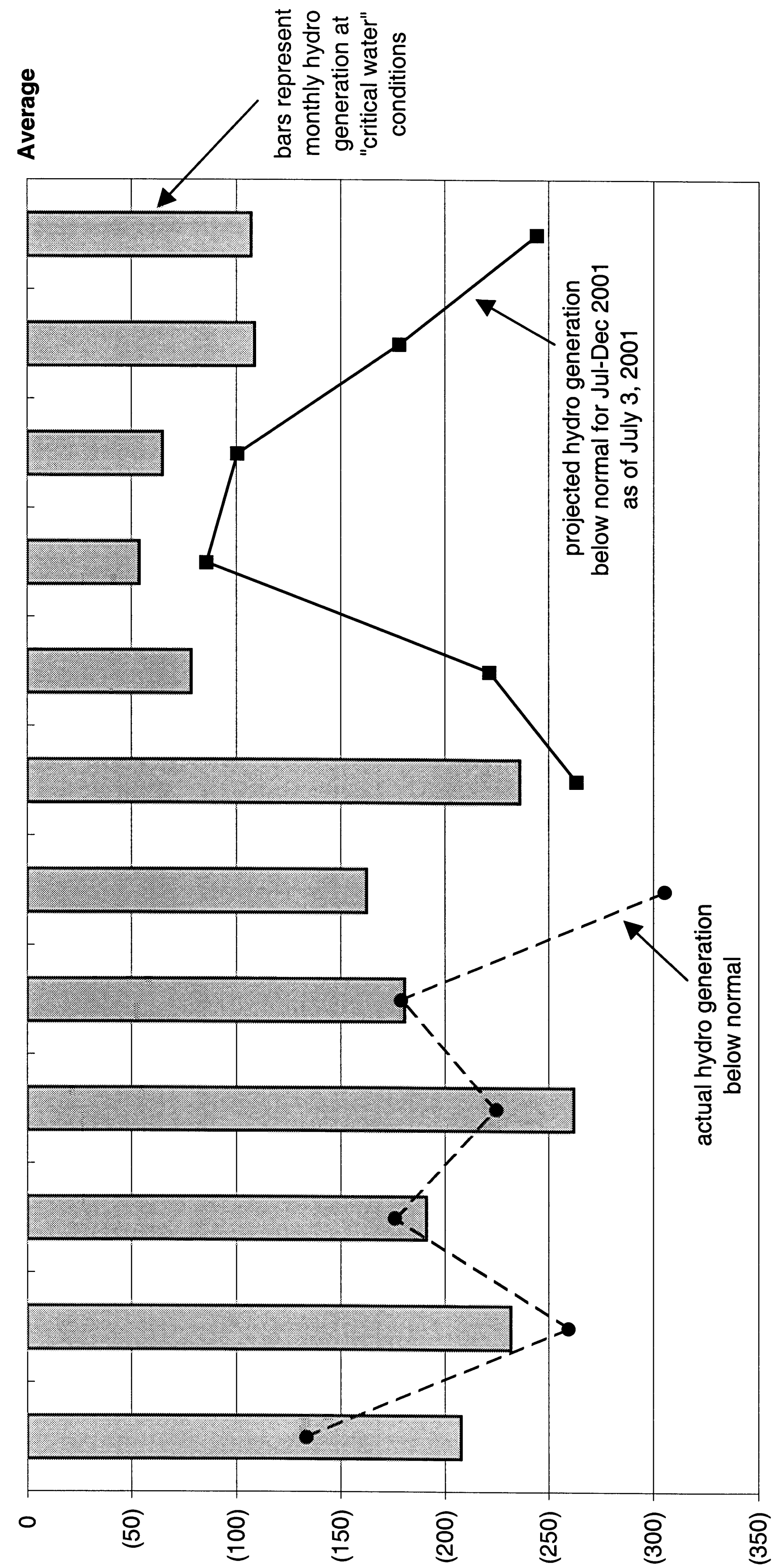
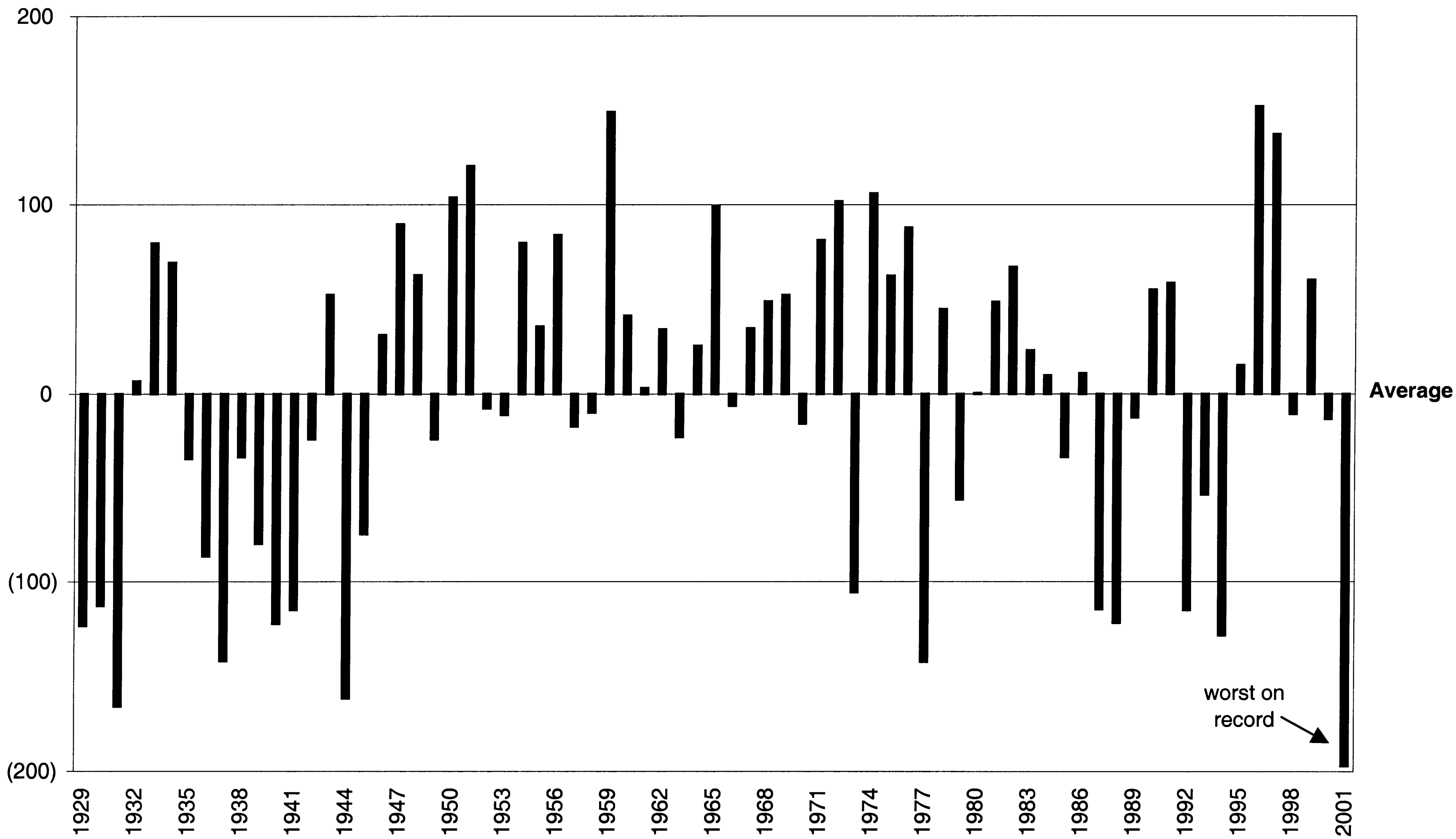


Exhibit No.__ (KON-2)
Case No. AVU-E-01-11
Avista
Page 1 of 2

AVISTA UTILITIES

1929 - 2001 Avista System and Mid-Columbia Hydro Generation

(aMW by Calendar Year)



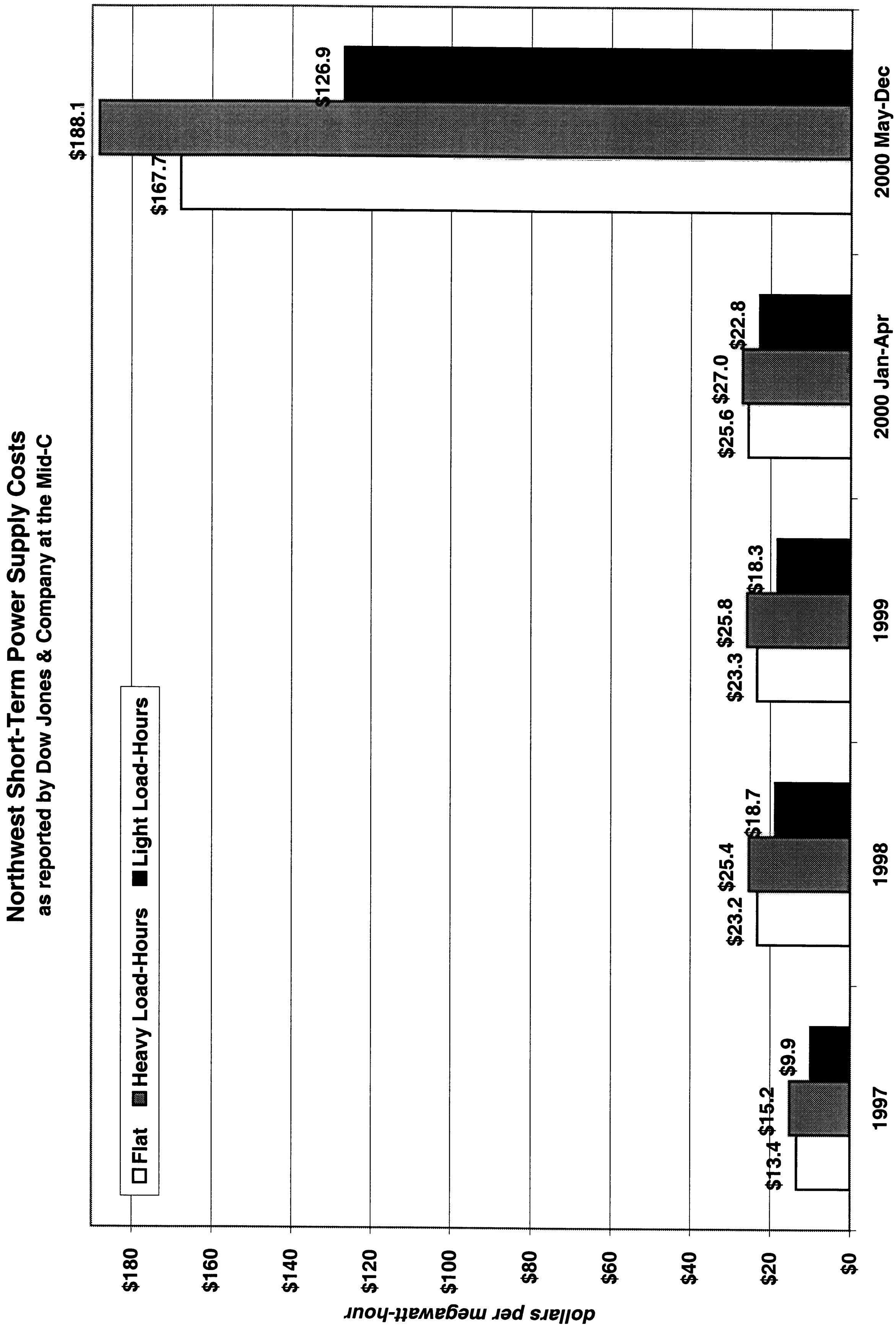
Note: 1929 - July 1988 generation per the NWPP Hydro Regulation Study.
August 1988 - June 2001 is actual generation.
July 2001 - December 2001 is projected generation.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-01-11

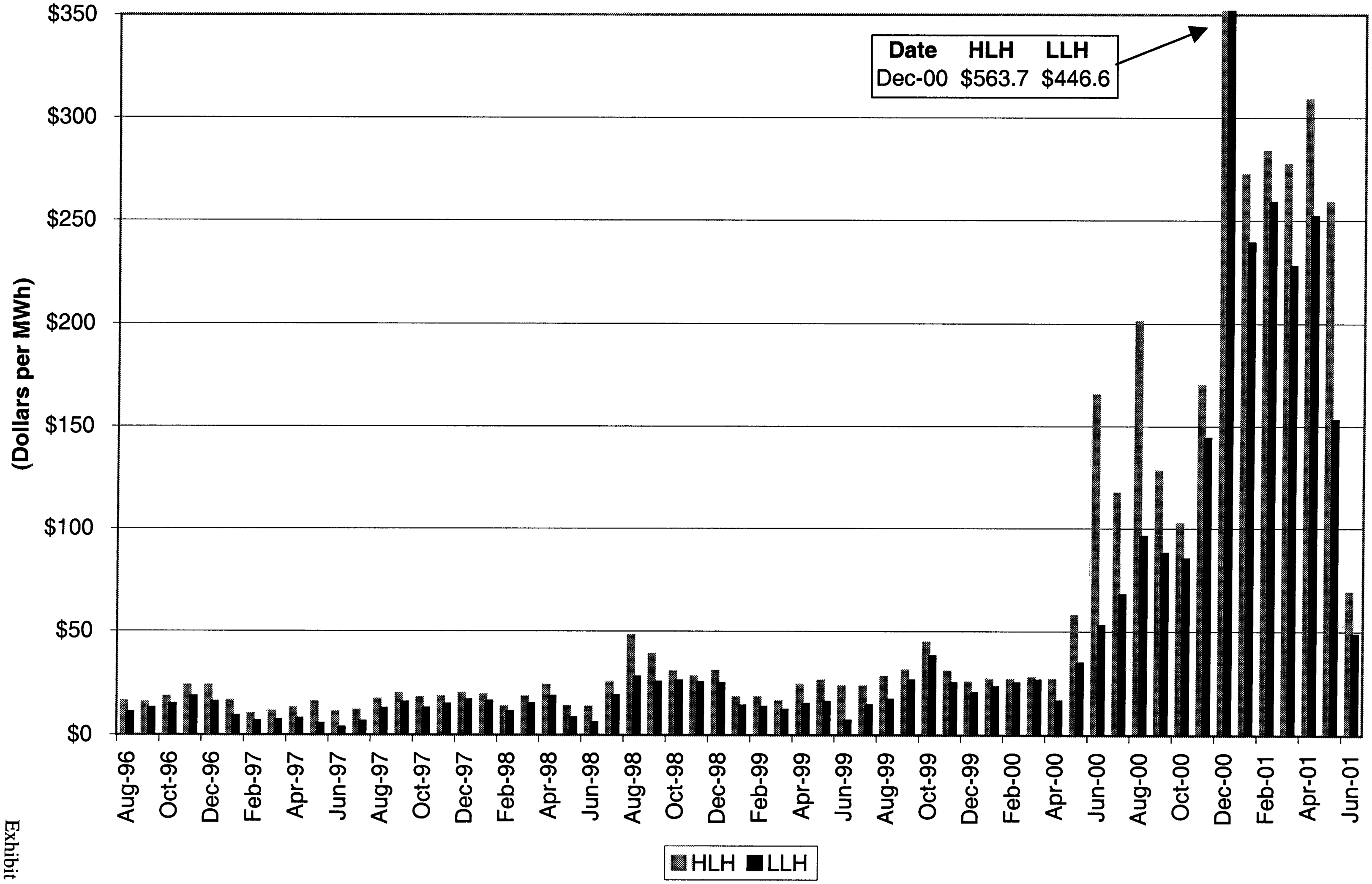
EXHIBIT NO. __ (KON-3)



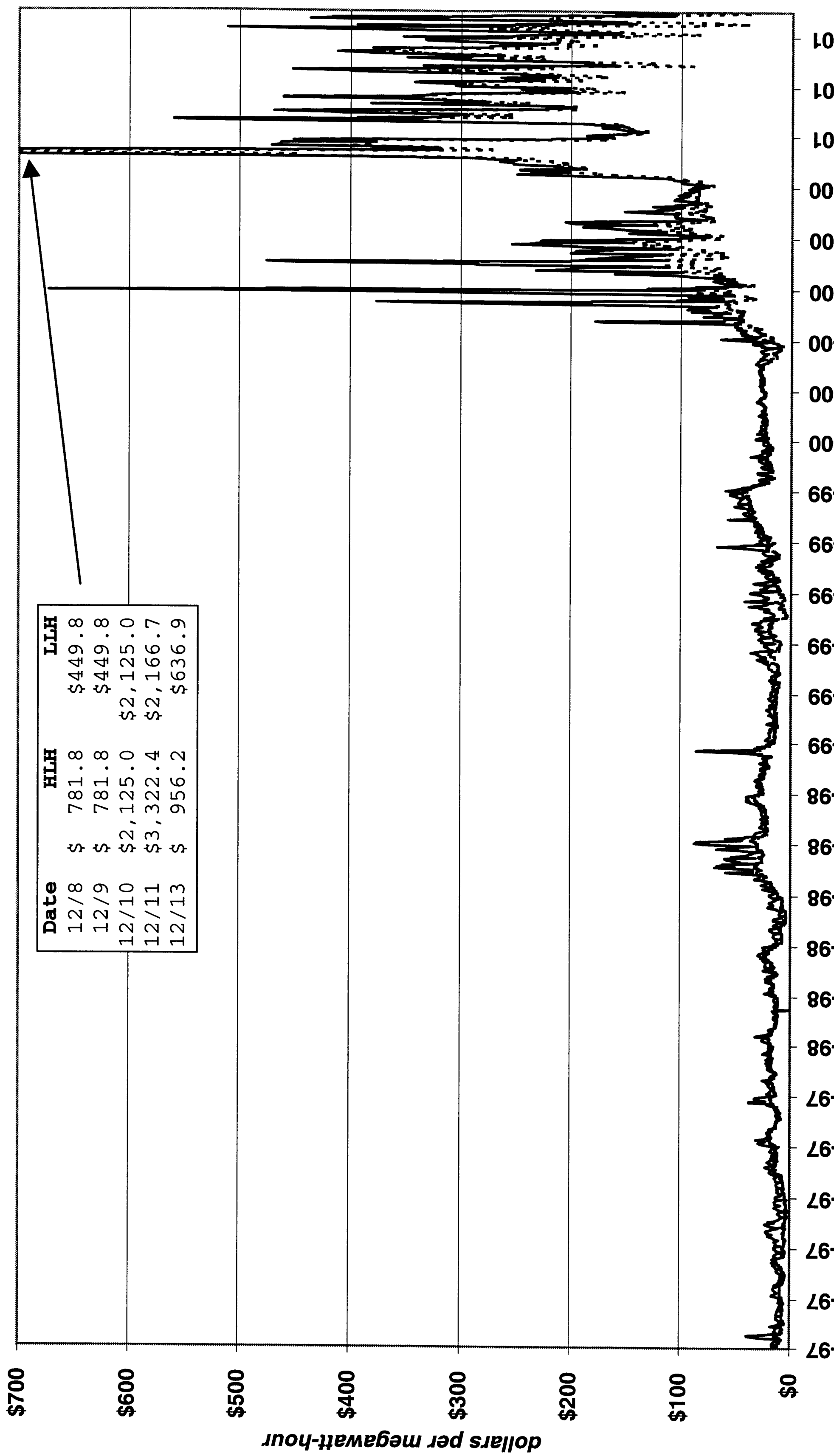
Northwest Short-Term Power Supply Costs
as reported by Dow Jones & Company at the Mid-C
Flat
Heavy Load-Hours
Light Load-Hours
dollars per megawatt-hour
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
1997
1998
1999
2000 Jan-Apr
2000 May-Dec
$13.4
$15.2
$9.9
$23.2
$25.4
$18.7
$23.3
$25.8
$18.3
$25.6
$27.0
$22.8
$167.7
$188.1
$126.9

Mid-Columbia Firm Electricity Index

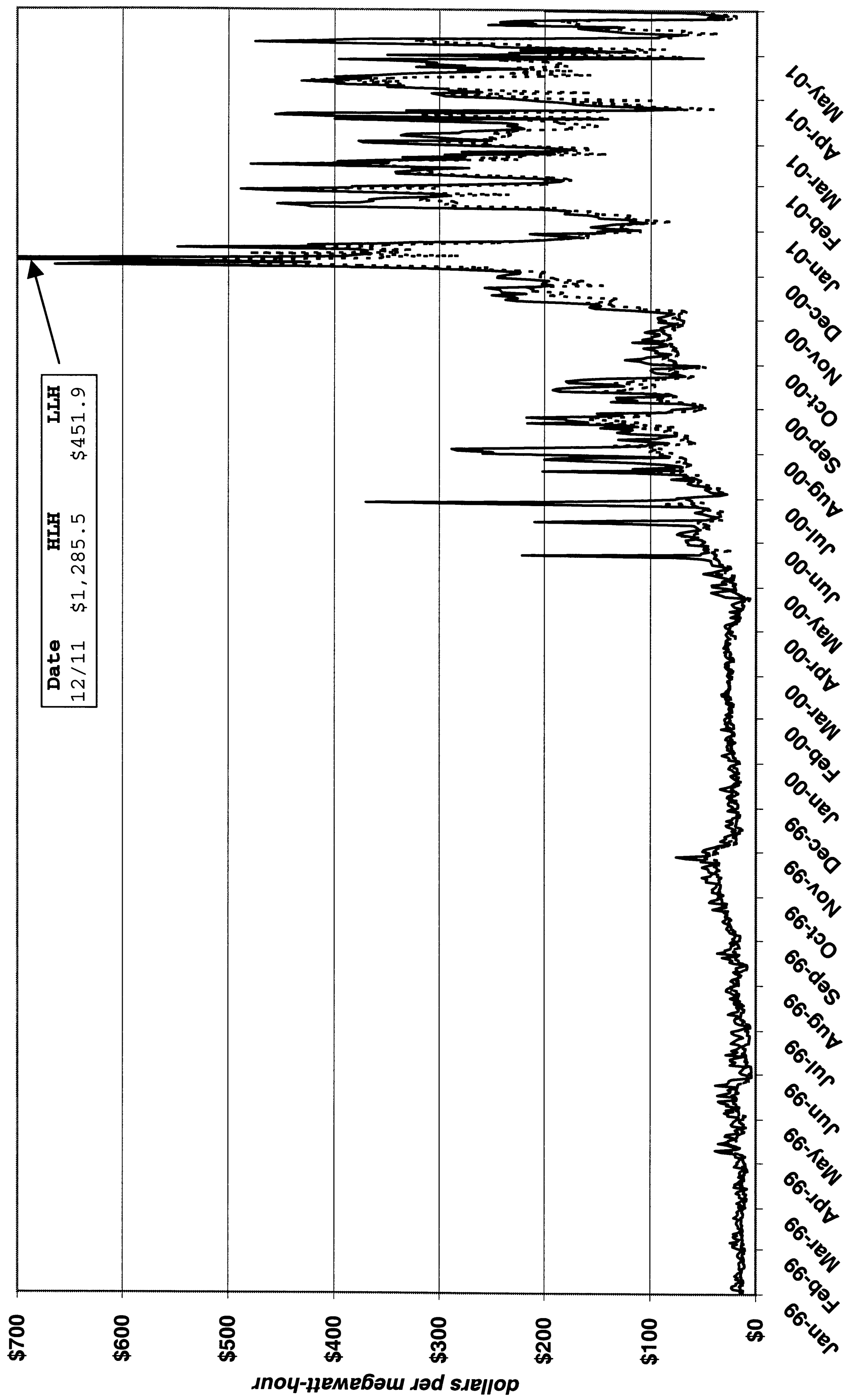
(as reported by Dow Jones & Company: August 1996-June 2001 monthly averages)



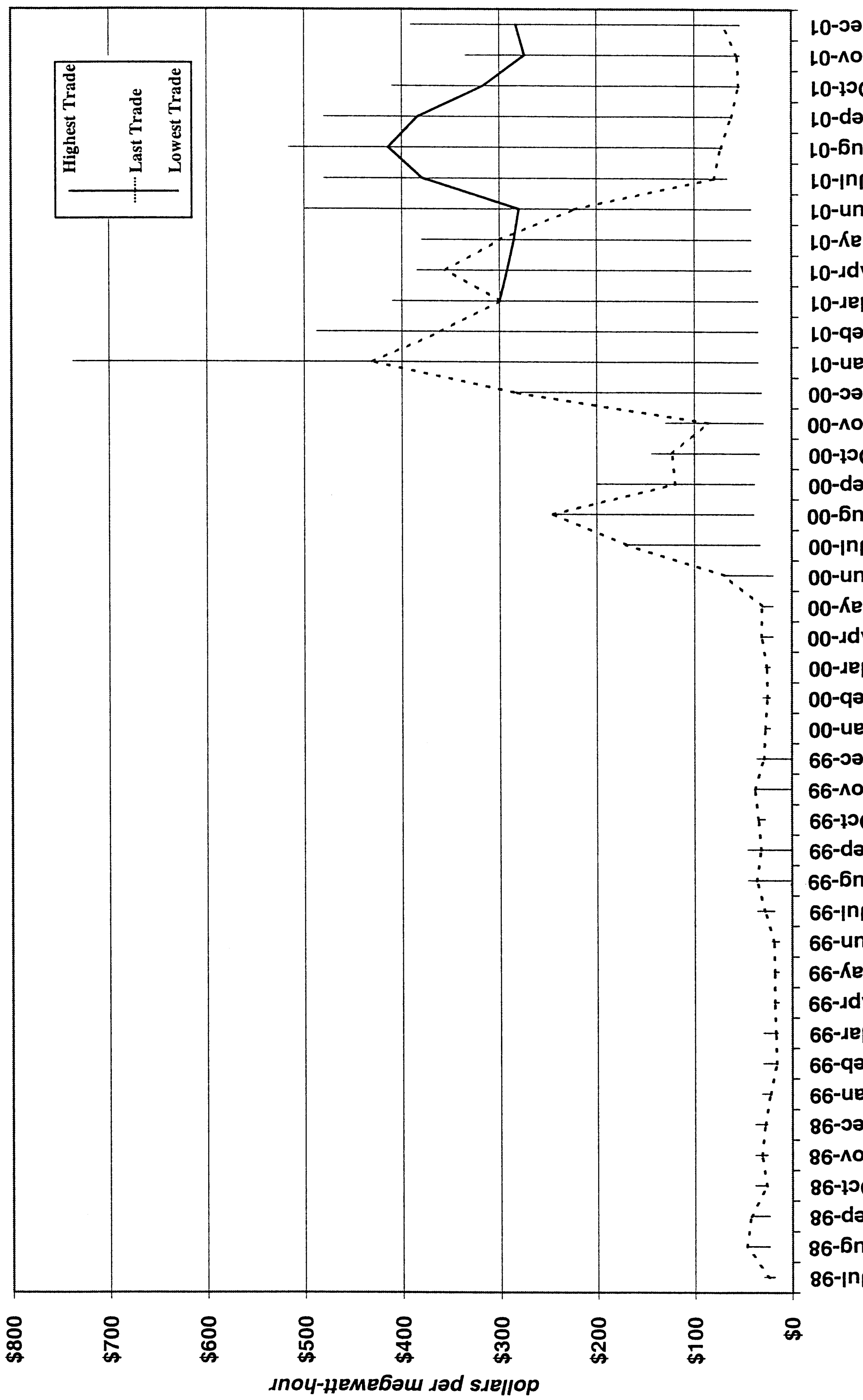
Mid-Columbia Daily Firm Electricity Index
as Reported by Dow Jones & Company
January 1997 through May 2001



Mid-Columbia Daily Non-Firm Electricity Index
as Reported by Dow Jones & Company
January 1999 through May 2001



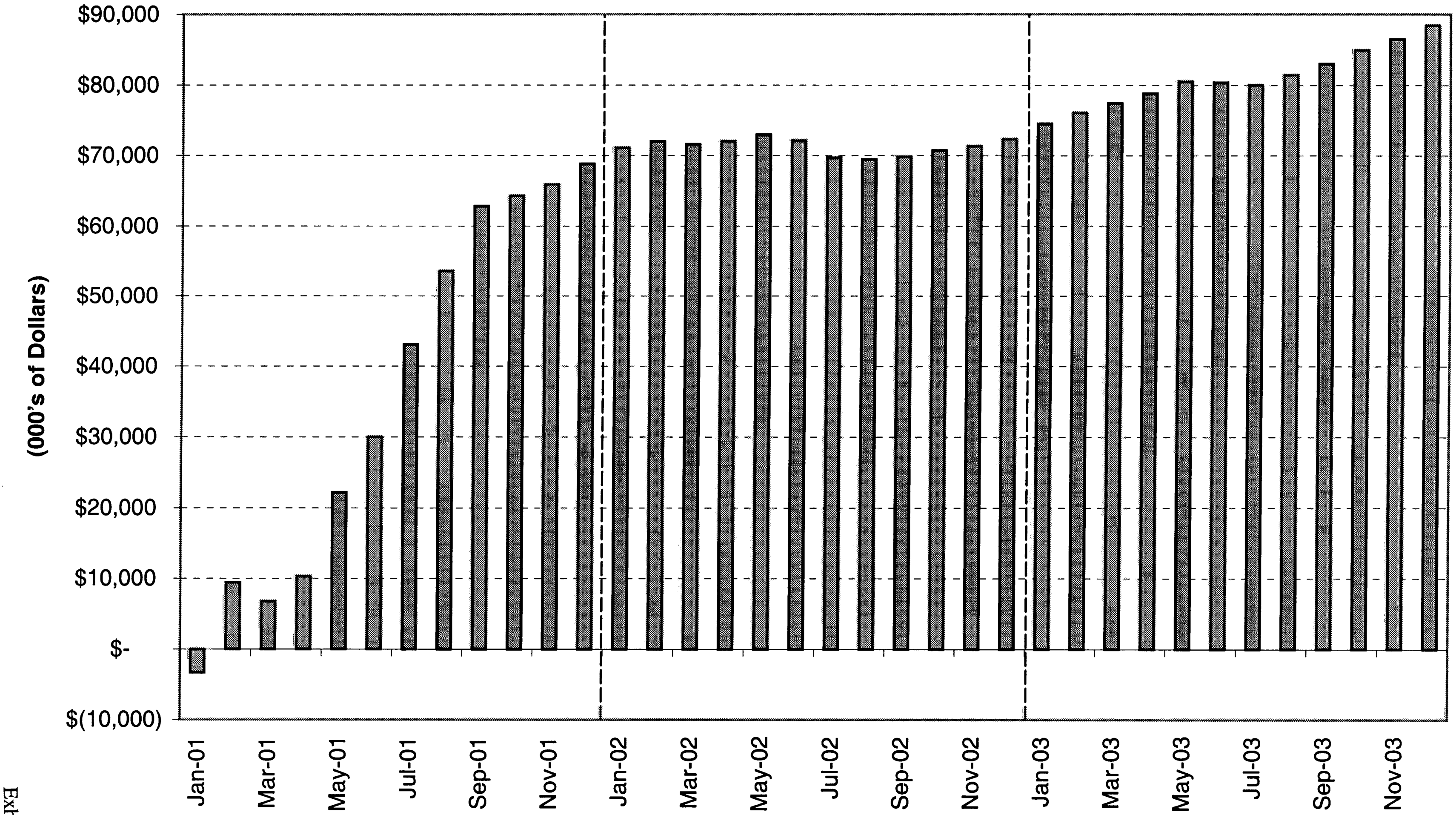
Mid-Columbia Forward Market Price Volatility
July 1998 - December 2001
trades through July 25, 2001



AVISTA UTILITIES

Projected Idaho Electric PCA Deferral Balances

(Using July 3 Forward Prices)



BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-01-11

EXHIBIT NO. __ (KON-4)

FT FINANCIAL TIMES Energy

Thursday, May 31, 2001

MegawattDaily

From the publisher of Gas Daily® and Coal Outlook

Massey calls for inquiry into market power methodology

FERC Commissioner William Massey, dissenting from two orders yesterday, strongly called for the commission to give up its current method of market power analysis.

"Our current standard is just plain outdated, inadequate and unreliable," Massey said.

Massey has previously attacked the "hub-and-spoke" method of market power analysis, which presumes market power if any single market participant holds a 20% market share.

In April, Pacific Gas & Electric and Southern California Edison made a similar argument in asking FERC to deny renewal of market-based rate authority to Williams Energy Marketing and Trading *(MWD 4/4)*. The two utilities argued that while Williams controls less than 20% of the generation resources in the state, it is still able to exercise market power. To renew its market-based rate authority, Williams should perform an analysis of market power using other means, the utilities said.

Massey said the events of the California wholesale power market — where no single generator or power seller holds close to 20% market share — during the past year indicate that market power can be exercised by any player holding a much smaller piece. The "20-percent share threshold is too simplistic," he said.

In one decision issued yesterday in draft form, the commission granted market-based rate authority to Sierra Southwest Cooperative

(Continued on page 8)

INSIDE THE MARKET REPORT

Key Hub Trades for Standard 16-Hour Daily Products

Weighted average index prices (in $/MWh) and volumes are shown for selected major hubs. More detailed price information is available on page X.

Delivery Point	Weighted Average Index	Trading Volume Reported
COB	180.20	125
Mid-Columbia	176.67	1,425
Palo Verde	175.64	1,375
ERCOT-B	35.12	1,500
Com Ed	16.57	350
Entergy	27.24	5,150
Cinergy	17.22	9,620
PJM	24.25	5,600
TVA	17.74	1,450

Bush, Davis agree to disagree on price caps

President Bush and California Gov. Gray Davis have a "fundamental disagreement over whether or not California is entitled to price relief," Davis said after the two met privately in Los Angeles on Tuesday to discuss the state's energy crisis.

Despite intensified arguments that continuing high wholesale power prices will hurt California and the larger U.S. economy, Davis was unable to persuade Bush to support temporary price controls in the state.

Bush again declined Davis' requests for caps on power prices. But California is legally "entitled" to price caps, Davis argued during a press briefing following his meeting with Bush.

"The president did not create this problem," Davis said of the power crisis. "Like me, he inherited a mess." Davis has lately stuck to his message that California is doing all it can to bring new power plants online and to reduce consumption.

The governor, who acknowledged the president's efforts in other areas to help California, said he and Bush have a "fundamental disagreement" over the issue of price caps. Davis said caps are necessary for California, which is short generation and could pay $50 billion to $70 billion this year for its

(Continued on page 7)

State regulators add views to Bush energy plan

Utility regulators from 13 states this week issued a set of national electricity policy recommendations directed at both state and federal lawmakers and officials.

"We feel timing is critical," Montana Public Service Commissioner Bob Anderson, leader of the effort, said. "President Bush issued his energy policy recommendations recently, and we commend him for it. Our recommendations will complement his and enrich the policy debate."

The report identifies seven principal policy areas. "These comprehensive policies present a balance between supply and demand, while recognizing the important role of energy efficiency, as well as environmental and consumer protection," Anderson said.

Policy-makers should improve existing generation technologies to increase efficiency and minimize environmental impact, the report says. Policies also should promote fuel diversity including "green" power sources.

To ensure reliability, transmission and distribution, companies should provide "adequate and efficient generation," the report says. Delivery companies also should provide a certain minimum level of reliability to all customers "as a part of basic electric service."

Because 95% of customer outages re-

(Continued on page 2)

Exhibit No.__ (KON-4)
Case No. AVU-E-01-11
Avista
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/avis ready to take his case to court ... *(from page 1)*

...ver purchases. Davis told Bush he would "pursue every recourse available" to "ensure that markets are functional and rates are just and reasonable."

Davis also said he hoped Bush would communicate to the two new FERC members "that California is entitled to price relief."

So far, federal regulators have taken steps to ensure a competitive power market in the long term, but they have refused to implement short-term caps.

In a meeting that Davis described as "cordial," the governor said he informed the president that he would do all he could to fight for Californians against high power prices charged by generators that Davis accuses of market manipulation.

Davis indicated that action would include lodging a lawsuit against the regulators at FERC. The agency's legal mandate is to ensure that power prices are "just and reasonable," and FERC ruled in a December order that the market was not competitive.

In that order and in subsequent actions, FERC implemented a series of measures aimed ...ironing out faults in California's market ...ucture and at limiting wholesale prices during power emergencies.

Davis and other state officials claim those actions have failed to limit price spikes and will not help the state avoid blackouts and high costs for power this summer. Three state agencies and the state Assembly have filed petitions within the last few days requesting a rehearing of the agency's latest order on price mitigation measures during power emergencies.

Speaking after his meeting with Bush, Davis indicated those filings are the first step in a legal process that could result in lawsuits against FERC. The state must first exhaust all legal and procedural remedies with FERC before turning to the courts, he said.

A lawsuit filed last week in federal court by senior Democrats in the state Senate and Assembly was dismissed Tuesday because those legislators had not first gone through all appeals channels directly available with FERC, Davis said. A three-judge panel at the Ninth Circuit Court of appeals dismissed the ...ition, saying only that the "petitioners have not demonstrated that this case warrants the intervention of this court."

FERC Chairman Curt Hebert seemed unfazed at the prospect of Davis' threatened legal action.

"I think the Ninth Circuit made it clear, FERC is doing our job appropriately," Hebert said at yesterday's commission meeting.

In addition to legal remedies to force federal regulators to act, Davis also pointed to Senate Democrats, who will take control of that body early next month, as potential partners who could help California by approving price cap legislation. California's Democratic senators, Dianne Feinstein and Barbara Boxer, have both introduced bills that would impose price caps in Western markets.

"I'm looking forward to working with the newly constituted United States Senate to make sure that the problems of California and the West ... get a full airing," Davis said.

Davis attempted to sway Bush in favor of price caps by arguing that a crisis-damaged California economy will hurt the nation and that the federal government is required by law to ensure reasonable rates.

But Bush, who has been steadfastly against price caps, explained his opposition to the caps in a speech at the World Affairs Council in Los Angeles. He also noted that the Clinton administration did not call for the imposition of price caps.

"We will not take any action that makes California's problems worse, and that's why I oppose price caps," Bush said. "Price caps do nothing to reduce demand, and they do nothing to increase supply. This is not only my administration's position, this was the position of the prior administration."

The president said his administration would help California by expanding the state's main north-south transmission line, Path 15; requiring federal facilities in the state to reduce demand 10%; and providing additional funding to low-income consumers to help offset rising electricity and gas prices.

The president also told Davis that he would dispatch newly installed FERC Commissioner Pat Wood, the former head of the Public Utility Commission of Texas, to California to investigate why natural gas prices are higher in the state than in other parts of the country.

Davis called Bush's offer "good news" and said the president agreed with him that it "made little sense for California to receive Texas natural gas at roughly $15 per British thermal unit, when New York is receiving the same gas at roughly $5.95 per British thermal unit."

The president wants Wood "to see if there is market manipulation" in the California natural gas market and "to review the wisdom of the Federal Energy Regulatory Commission's decision two years ago," when, Davis said, FERC suspended a tariff that controlled the transportation prices of natural gas when it flows from Texas to other parts of the country. MS/ADP

Energy economists to testify on market manipulation

California legislators will hear testimony later today from two prominent energy economists on allegations that power generators have colluded to drive up prices in the state's wholesale power markets.

Severin Borenstein and Alfred Kahn are scheduled to testify before the state Senate's Select Committee to Investigate Price Manipulation of the Wholesale Energy Market. Kahn may address issues of physical withholding of power supplies by generators, while Borenstein would likely brief senators on economic models exhibiting generators' ability to exercise market power to raise prices, a representative of committee Chairman Joseph Dunn indicated.

The select committee has taken testimony in three earlier hearings from state energy officials on plant outages and their effect on prices. Within the next several weeks, the committee also plans to hear from generators, according to the representative.

The "big five" out-of-state generators — Duke, Dynegy, Reliant, Williams/AES and Mirant — will be invited to give their side of the story, as will energy marketer Enron, he said. Those companies have been repeatedly accused by state officials of gouging consumers and engaging in illegal activity.

Borenstein, Kahn and eight other economists last week co-signed a letter to President Bush arguing for the imposition of short-term price caps on wholesale markets. The economists asserted that the failure of deregulation in California could harm the development of competitive electricity markets across the nation. ADP

FT
FINANCIAL TIMES Energy

Thursday, June 14, 2001

MegawattDaily

From the publisher of Gas Daily® and Coal Outlook

Calif. inks deal with QFs, will release details on long-term contracts

California officials have reached agreements with two groups of small generators that will return the full amount of power contracted by those facilities back to the market, adding between 100 MW and 300 MW of additional power to the state's grid this summer, Gov. Gray Davis said yesterday.

Contracts signed with two groups of qualifying facilities establish new prices for the power they will supply to the second largest investor-owned utility in the state, Southern California Edison, Davis said.

The deals also provide for marginal payment of back debts owed by the utility to the generators, provided the individual facilities produce additional energy at their facilities.

But the effective date of the agreed-to prices is linked to approval by the state Legislature of an agreement between SoCalEd's parent company and the state. The memorandum of understanding between Davis and Edison International would pave the way for the state's purchase of the utility's power lines.

Negotiations between the state and the QFs have resulted in bringing 95% of the power produced by those generators back onto the market, Davis said. Numerous QFs had been withholding their output from the market in protest over nonpayment of past bills by California's largest utilities.

The output of QFs serves up to one-third of California's total

(Continued on page 8)

INSIDE THE MARKET REPORT

Key Hub Trades for Standard 16-Hour Daily Products 06/14/01

Weighted average index prices (in $/MWh) and volumes are shown for selected major hubs. More detailed price information is available on page 3.

Delivery Point	Weighted Average Index	Trading Volume Reported
COB	57.33	75
Mid-Columbia	56.20	2,100
Palo Verde	62.59	2,025
ERCOT-B	41.17	1,950
Com Ed	49.10	2,050
Entergy	51.98	5,900
Cinergy	53.44	11,000
PJM	55.26	8,750
TVA	52.28	2,000

Cheney, Hebert hold firm on energy policy

Vice President Dick Cheney and FERC Chairman Curt Hebert both pledged yesterday to stay the course when it comes to energy policy. But while both men faced a friendly audience at the Energy Efficiency Forum yesterday at the National Press Club in Washington, their remarks seemed aimed more at winning over a skeptical audience in California.

Cheney and Hebert emphasized the importance of market remedies — and reaffirmed their opposition to price controls. Hebert, for one, was adamant that recent FERC measures would suffice to create a better-functioning market out West.

"California does not mean an end to competition," he said.

Cheney repeated the main selling points of the administration's recently introduced national energy policy. And while he warned of the possible economic impact of the current supply situation, the vice president said that the nation's energy problems could be fixed with a dose of "resolve, ingenuity and clarity of purpose."

The remedies that Cheney listed include the construction of a new gas pipeline that would run from Alaska's North Slope, a proposal that Cheney called "relatively non-

(Continued on page 7)

FERC clears National Grid purchase of NiMo

With a specific provision on accounting procedures, FERC yesterday approved New York-based Niagara Mohawk Holdings' proposed acquisition by National Grid USA, the U.S. branch of the British transmission utility.

National Grid USA, which operates two transmission and distribution utilities in New England, offered to buy NiMo last September in a $3 billion cash and stock transaction that includes assumption of $5.9 billion in NiMo debt *(MWD 9/6/00)*. NiMo serves 1.5 million electricity and 540,000 natural gas customers in upstate New York.

The combined company, which would be a new holding company registered in the United Kingdom under the name National Grid Group (the same name as the existing overall company), would serve 3.3 million electricity customers in the United States, placing it among the top 10 in terms of customers served.

NiMo will continue as the local utility and will remain under the regulations of New York state.

Both companies have sold substantially all of their generation assets — NiMo's major remaining asset, its interests in the Nine Mile Point nuclear plants, has been committed to Constellation Energy Group — so FERC found no competitive market issues there.

(Continued on page 2)

FT FINANCIAL TIMES Energy

Megawatt Daily's MarketReport

Monday, December 11, 2000

Indexes and Transaction Record for 12/11/00

Explanations

Index — Volume-weighted average of all trades reported.
Absolute Low — Lowest trade reported.
Absolute High — Highest trade reported.
Trading Volume Reported — Volume of trades per hour for each of 16 peak hours. This figure is a total of all trading volume reported to MWD for each delivery site; because every effort is made to capture both sides of every deal reported, MWD recognizes that this figure includes duplicate volumes, and the figure should be used as a trend indicator not necessarily as an indicator for transmitted volumes.
Total Peak Volume — Volume for all peak hours, found by multiplying the trading volume by 16.
Number of Trades — This figure is calculated by dividing the trading volume reported by 50 MW/h for all Central and East listings; numbers of trades for delivery points in the West are calculated by dividing by 25 MW/h.

Methodology

The prices displayed in the table to the right are for power, in $/MWh, traded at the delivery points and regions listed. Peak hours are 0600-2200 hrs.; PJM and New York peak hours are 0700-2300. Off-peak hours generally start at 2200 hrs. on the date before the delivery date and end at 0600 on the delivery date. Not included are 24-hour deals categorized in some NERC regions as off-peak hours over Saturdays and Sundays. Transactions at the hubs listed in the separate table at the top of this page are financially firm. Deals at other locations may be unit-firm or system-contingent, and may include capacity reservation charges. Transactional data is gathered from utilities, marketers, co-ops, brokers, municipals and government power agencies. Deals done in the West are excluded if done after 1015 hrs. PT; deals done in the East and Central areas are excluded if done after 1100 hrs. CT. The middle column is the volume-weighted average of all deals reported and should be used for indexing purposes. The common range represents pricing for most of the trading volume; the absolute range represents lowest and highest prices reported. Copyright 2000 by Financial Times Energy.

Trades for Standard 16-Hour Daily Products; *all prices and volumes in $/MWh*

Delivery Point	Weighted Average Index	Absolute Low	Absolute High	Trading Volume Reported	All Peak Hours Volume	Number of Trades Reported
West						
COB	$3,000.00	$3,000.00	$3,000.00	25	400	1
Four C	—	—	—	0	0	0
Mead, Nev.	—	—	—	0	0	0
Mid-Columbia	$4,175.00	$3,000.00	$5,000.00	100	1,600	4
NP15	—	—		0	0	0
Palo Verde	$395.00	$360.00	$425.00	75	1,200	3
SP15	$350.00	$350.00	$350.00	25	400	1
Central						
ERCOT-8	$65.59	$60.00	$75.00	850	13,600	17
Ameren	—	—	—	0	0	0
Com Ed, into	$44.39	$40.00	$52.00	900	14,400	18
MAIN North	$63.33	$58.00	$120.00	300	4,800	6
MAIN South	—	—	—	0	0	0
MAPP North	$60.94	$50.00	$75.00	160	2,560	3
MAPP South	—	—	—	0	0	0
Entergy, into	$67.40	$50.00	$76.00	2,000	32,000	40
SPP	$65.90	$58.00	$75.00	500	8,000	10
East						
Cinergy	$48.47	$44.00	$53.00	6,550	104,800	131
North ECAR	$51.52	$45.00	$55.00	1,405	22,480	28
PJM-West	$49.01	$46.00	$54.00	2,800	44,800	56
Nepool	$74.00	$72.00	$80.00	500	8,000	10
NY Zone G	$67.50	$67.50	$67.50	200	3,200	4
NY Zone A	$57.85	$57.00	$59.00	600	9,600	12
NY Zone J	$81.00	$81.00	$81.00	50	800	1
VaCar	$46.00	$46.00	$46.00	150	2,400	3
Southern	$45.00	$45.00	$45.00	50	800	1
TVA, into	$43.92	$43.00	$47.00	1,200	19,200	24
Fla.-Ga.	$42.50	$40.00	$45.00	100	1,600	2
Fla. in-state	—	—	—	0	0	0

Trades for Standard Forward Products *(all prices in $/MWh)*

Delivery Point	Next Week 12/18 to 12/22		Balance of Month 12/12 to 12/31		Prompt Month 01/01				
	Low	High	Low	High	Low	High	Index	All pk. hrs. vol.	No. of Trades
West									
COB	—	—	—	—	—	—	—	0	0
Mid-Columbia	—	—	—	2,000.00	575.00	800.00	675.00	1,200	3
NP15	—	—	—	—	—	320.00	320.00	400	1
Palo Verde	—	—	—	—	250.00	375.00	300.00	1,200	3
SP15	—	—	—	—	—	—	—	0	0
Central									
Com Ed, into	—	75.00	—	68.00	—	—	—	0	0
Entergy, into	—	—	—	—	—	—	—	0	0
East									
Cinergy, into	72.00	85.00	—	70.00	—	—	—	0	0
PJM-West	—	—	—	61.00	—	—	—	0	0
NEPOOL	82.00	90.00	82.00	85.00	—	—	—	0	0
NY Zone G	—	—	—	—	—	—	—	0	0
NY Zone A	60.00	60.50	—	—	—	—	—	0	0
NY Zone J	—	—	—	—	—	—	—	0	0
TVA, into	—	66.00	—	—	—	—	—	0	0

Ranges and Indexes of Trades for Standard Off-Peak Products

Delivery Date: 12/11/00

	Wtd. Av. Index	Absolute Low	Absolute High	Trading Vol. Reported
West				
COB	—	—	—	0
Four C	$275.00	$275.00	$275.00	25
Mead. Nev.	—	—	—	0
Mid-C	$2,016.67	$1,550.00	$2,500.00	75
NP15	—	—	—	0
Palo Verde	$275.00	$275.00	$275.00	25
SP15	—	—	—	0
Central				
ERCOT-8	—	—	—	0
Ameren	—	—	—	0
Com Ed. into	$19.00	$19.00	$19.00	300
MAIN North	—	—	—	0
MAIN South	—	—	—	0
MAPP North	$21.00	$21.00	$21.00	125
MAPP South	$20.00	$20.00	$20.00	100
Entergy. into	—	—	—	0
SPP	$17.04	$13.00	$23.50	260
East				
Cinergy	—	—	—	0
North ECAR	$19.50	$19.00	$19.55	1,157
PJM-West	—	—	—	0
Nepool	—	—	—	0
NY Zone G	—	—	—	0
NY Zone A	—	—	—	0
NY Zone J	—	—	—	0
VaCar	—	—	—	0
Southern	—	—	—	0
TVA, into	—	—	—	0
Fla.-Ga.	$25.00	$25.00	$25.00	50
Fla. in-state	—	—	—	0

MGE, Alliant propose plant for university

A proposal between Madison Gas & Electric (MGE), Alliant Energy, the University of Wisconsin-Madison and Wisconsin's Department of Administration may result in a $170 million, 90- to 100-MW, natural gas-fired power plant on school ground that could solve a long-term energy crunch facing both the university and the city, the parties said last week.

If the plant gets all approvals necessary, the two utilities will jointly plan and oversee construction of the facility, which is anticipated to start in summer 2002. Plant operation is expected to begin in late 2003 or spring 2004.

Once construction is complete, MGE would own the facility with a third-party investor but would retain full operational control. Alliant will act as project manager. Although not a specified owner, Alliant will be paid for its services, company representative Chris Schoenherr said.

The proposed site at the university has the necessary infrastructure in place to support the facility, including electric transmission lines, a power substation and natural gas lines. MCM

Dailies scream to $5,000 at Mid-C, $3,000 at COB

Western Markets

The relentless upswing in next-day prices prevailed, with dailies trading to $5,000 at Mid-Columbia and $3,000 at COB.

"This is history," one source said. "Someone who buys power at that price [$5,000] is walking wounded. Actually, they're not even walking."

Overall, next-day volume was sparse. Deals arranged for today's delivery traded up to $425 at Palo Verde and near $350 at SP15.

In the bilateral market, off-peak for today traded near $275 at Palo Verde and at Four Corners.

The extreme pressure on prices carried over into the term markets, where balance-of-the-month sold for $2,000 at Mid-C and January there sold for $800 for a third consecutive day.

Crippled by idled power plants and tight energy imports, the state's power grid strained to meet the load going into the weekend. The danger of blackouts, caused by cold weather and an unprecedented drop in the energy supply, was expected to grow severely today, as an Arctic front blows down the West Coast from Canada.

Going into the weekend, California Power Exchange prices for Saturday peak were $251.23, with off-peak $256.79 and the 24-hour weighted average at $252.79. A day earlier, prices were fractions of a cent above $250.

The Bonneville Power Administration had no surplus power to sell at least through Saturday.

Friday began with a Stage 2 declaration by the California Independent System Operator — the fifth such declaration in as many days and the ninth in three weeks.

Also firming up power prices was the cost of natural gas, which reached as high as $63 at COB/Malin, Ore., $61 at the Pacific Gas & Electric Citygate and $55 at the Southern California Border.

At Palo Verde, January ranged $250-$375 and near $320 at NP15.

Second-quarter 2001 traded as high as $215 at Mid-C and in a tight range to $190 at Palo Verde.

Third-quarter 2001 sold at or above $290 at Palo Verde. KW/NM

Transmission problems force Entergy to mid $70s

Central Markets

Entergy dailies opened at $50, about $23 lower than the previous day's trades. However, they soon regained ground, passing the high from the day before.

By the end of the day deals were done at $76, a net gain of $1. Traders were not certain what was driving prices up, but suspected transmission constraints.

In MAIN, ComEd dailies fell even further, about $16 to the low $50s. Off-peak sold near $19.

Weekend trades moved in the low $30s and off-peak sold in the low $20s.

After undergoing a hot shutdown last week, ComEd's 828-MW nuke unit, Quad Cities 1, began powering back up after repairs.

Northern MAIN dailies moved around the low $60s. However, the same unfortunate player who all last week caught the high deals paid around $120 for a much-needed package. Weekend peak sold in the upper $20s.

Ameren reported weekend off-peak deals near $20.

Light weekend demand helped push northern MAPP dailies down about $20, to $75.

Central Generation Outage Report for December 11

Information from the Nuclear Regulatory Commission is sometimes outdated, and not all utilities respond to requests for verification of unit status. Copyright 2000 by FT Energy

Unit Name, Operator	MW	NERC Region	Unit Status	Scheduled restart or outage date
LaSalle 2 ComEd	828	MAIN	Nuclear; operating at 100% following Oct. 6 refueling outage	Full power Dec. 8
Quad Cities 1 ComEd	828	MAIN	Nuclear; operating at 1% after hot shutdown Dec. 6	Start up on Dec. 7

Exhibit No.__ (KON-4)
Case No. AVU-E-01-11
Avista
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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-01-11

EXHIBIT NO. __ (KON-5)

PCA MECHANISM

Two different methods have been used to quantify the changes in power supply expenses. For the months of July through December 2000 the Company used a methodology that calculated net power supply expenses based on actual hydro generation and actual Rathdrum generation and fuel costs, and actual average short-term energy purchase and sales prices. This method modeled the Company's net energy purchases based on the authorized level of resources and obligations included in the Company's last general rate case. Modeled quantities of purchases and sales of energy were multiplied times the actual average short-term energy prices to determine net power costs. Net power supply expenses were compared to the authorized levels plus the difference between actual and authorized PURPA expenses to determine the change in net power supply expense on a system basis. The Idaho allocation of the net expense change was the power cost adjustment for the month.

The Idaho Public Utilities Commission in its Order No. 28775, dated July 11, 2001, approved the Company's request to modify the deferred accounting mechanism to include certain other power supply related components and actual system load requirements in the deferral calculation effective January 1, 2001. The Order also eliminated a one-month lag accounting treatment. High retail loads, due to cold weather and customer growth, and energy prices that greatly exceeded retail rates had created a situation where increased retail loads were significantly increasing power supply expenses. The old power cost adjustment mechanism did not include that increased expense because the retail load under the old method was fixed at the authorized level.

Changes in wholesale loads have also impacted the amount of power that needs to be purchased. Wholesale loads are impacted by the expiration of both purchase and sales contracts and by increased takes under contract options that were implemented because of the high short-term market prices. The new methodology, effective January 1, 2001, compares the actual and authorized amounts in FERC accounts 555 (Purchased Power), 501 and 547 (Fuel) and 447 (Sales for Resale) to the same authorized accounts to compute the change in net power supply expense. The Company is only allowed to defer 90% of the difference in the FERC accounts listed above. This methodology also includes a retail revenue adjustment. The retail revenue adjustment uses the variable cost of power supply on the margin accepted in the Company's last general rate case which is $21.23 MWh. This rate is multiplied by the difference between authorized and actual retail loads to account for the revenue offset to the power supply costs. A summary of the deferral calculations for January through June 2001 are provided on pages 3 of this Exhibit.

AVISTA CORPORATION
IDAHO POWER COST DEFERRALS
JANUARY 2001 - JUNE 2001 ACTUALS

Line No.	IDAHO 2001 ACTUALS	TOTAL	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
1	555 Purchased Power	$457,942,206	$86,999,030	$121,727,775	$91,835,762	$48,673,403	$63,958,416	$44,747,820
2	501 Thermal Fuel	$7,692,924	$1,217,053	$1,375,695	$1,220,912	$1,177,612	$1,277,559	$1,424,093
3	547 CT Fuel	$44,381,184	$7,925,269	$7,114,096	$7,062,210	$10,092,148	$7,484,944	$4,702,517
4	447 Sale for Resale	$358,166,144	$71,252,676	$99,255,910	$81,075,328	$9,327,229	$70,442,383	$26,812,618
5	Actual Net Expense	$151,850,170	$24,888,676	$30,961,656	$19,043,556	$50,615,934	$2,278,536	$24,061,812
6	PGE Capacity Revenue True-up	-$6,672,600	-$1,112,100	-$1,112,100	-$1,112,100	-$1,112,100	-$1,112,100	-$1,112,100
7	Adjusted Actual Net Expense	$145,177,570	$23,776,576	$29,849,556	$17,931,456	$49,503,834	$1,166,436	$22,949,712
	AUTHORIZED NET EXPENSE - SYSTEM	TOTAL	JAN	FEB	MAR	APR	MAY	JUN
8	555 Purchased Power	$75,926,976	$15,711,988	$14,215,669	$14,910,044	$12,403,835	$9,565,530	$9,119,910
9	501 Thermal Fuel	$14,277,373	$1,759,429	$2,283,737	$3,120,234	$2,460,430	$2,614,555	$2,038,988
10	547 CT Fuel	$1,023,674	$668,236	$77,969	$77,136	$77,916	$77,136	$45,281
11	447 Sale for Resale	$69,658,327	$10,568,038	$10,322,459	$11,880,813	$11,060,010	$13,415,766	$12,411,241
12	Authorized Net Expense	$21,569,696	$7,571,615	$6,254,916	$6,226,601	$3,882,171	-$1,158,545	-$1,207,062
13	Actual - Authorized Net Expense	$123,607,874	$16,204,961	$23,594,640	$11,704,855	$45,621,663	$2,324,981	$24,156,774
14	Northeast CT Emissions Expense	$1,335,365	$0	$ 92,040	$ 313,425	$ 371,791	$ 382,715	$ 175,394
15	Idaho Allocation @ 33.18%	$41,456,166	$5,376,806	$7,859,240	$3,987,665	$15,260,628	$898,414	$8,073,413
16	ID Retail Revenue Adj	-$4,202,505	-$1,064,975	-$1,190,404	-$478,695	-$667,201	$174,537	-$975,767
17	Centralia Capital & O&M Credit	-$1,408,998	-$234,833	-$234,833	-$234,833	-$234,833	-$234,833	-$234,833
18	BOULDER PK CAP & O&M-ID SHARE	$0						
19	SIP CAP & O&M - ID SHARE	$0						
20	DEVIL'S GAP-ID SHARE	$0						
21	K. FALLS BI-FUEL-ID SHARE	$0						
22	Retail BuyBack Costs-ID SHARE	$0						
22	Net Power Cost Increase (Decrease)	$35,844,663	$4,076,998	$6,434,003	$3,274,137	$14,358,594	$838,118	$6,862,813
23	90% of Net Power Cost Change	$32,260,197	$3,669,298	$5,790,603	$2,946,723	$12,922,735	$754,306	$6,176,532
24	Total Power Cost Deferral	$32,260,197	$3,669,298	$5,790,603	$2,946,723	$12,922,735	$754,306	$6,176,532

NOTE: Postive number deferrals are surcharges; negative number deferrals are rebates.

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Exhibit No.__ (KON-5)
Case No. AVU-E-01-11
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