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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	))))))))	CASE NO. AVU-E-04-01 DIRECT TESTIMONY OF WILLIAM G. JOHNSON

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

Q. Please state your name, business address, and present position with Avista Corporation.

A. My name is William G. Johnson. My business address is 1411 East Mission Avenue, Spokane, Washington, and I am employed by the Company as a Senior Power Supply Analyst in the Energy Resources Department.

Q. What is your educational background?

A. I graduated from the University of Montana in 1981 with a Bachelor of Arts Degree in Political Science/Economics. I obtained a Master of Arts Degree in Economics from the University of Montana in 1985.

Q. How long have you been employed by the Company and what are your duties as a Senior Power Supply Analyst?

A. I started working for Avista in April 1990 as a Demand Side Resource Analyst. I joined the Energy Resources Department as a Power Contracts Analyst in June 1996. My primary responsibilities involve long-term resource planning issues.

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

A. My testimony will 1) describe the adjustments to the 2002 test period power supply revenues and expenses, and 2) describe the new base level of power supply costs for Power Cost Adjustment (PCA) calculation purposes, using the proforma costs proposed by the Company in this filing. A table of contents for my testimony is as follows:

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

A. Yes. I am sponsoring Exhibit No. 10, Schedules 1 through 4, which were prepared under my supervision and direction.

Q. Are other company witnesses providing testimony regarding issues you are addressing?

A. Yes. Company Witness Kalich provides detailed testimony on the AURORA model used by the Company to develop a portion of the proforma power supply revenues and expenses included in my exhibits.

II. SUMMARY

Q. Please provide an overview of your direct testimony.

A. My testimony explains adjustments made to normalize power supply revenue and expense items in the proforma period compared to the 2002 test period. This involves estimating revenues and expenses based on normal stream flow and weather conditions, and expected wholesale market power prices. In addition, adjustments are made to reflect known and measurable power contract changes between the 2002 test period, and the time period that retail rates are expected to be in effect (i.e., the proforma period beginning September 1, 2004 and ending August 31, 2005). The net effect of my adjustments to the 2002-test period power supply net expense is a decrease of $30,522,000 on a system basis. The Idaho allocation of this adjustment is incorporated into the revenue requirement calculation for the Idaho jurisdiction by Witness Falkner.

III. PROFORMA POWER SUPPLY COSTS

Overview

Q. Please identify the specific power supply cost items that are covered by your testimony and the total adjustment being proposed.

A. Exhibit No. 10, Schedule 1 identifies the power supply expense and revenue items that fall within the scope of my testimony. These revenue and expense items are related to power purchases and sales, wheeling expenses, thermal fuel expenses and other miscellaneous power supply revenues and expenses identified in Exhibit No. 10, Schedule 1.

Q. What is the basis for the adjustments to the 2002 actual power supply revenues and expenses?

A. Adjustments are made to set the power supply revenues and expenses based on normal weather and normal stream flows. The AURORA model is used to normalize power supply revenue and expenses that are dependent upon weather and stream flows. The AURORA Model dispatches Company resources on an hourly basis and calculates the level of generation from the Company's thermal resources along with the short-term purchases and sales required to serve system requirements.

Adjustments are also made to reflect known and measurable contract changes between the 2002 test period and the proforma period. The Company has included proforma power supply adjustments to reflect power costs for the twelve-month period beginning September 1, 2004 and ending August 31, 2005.

Q. What changes has the Company made in the calculation of normal power supply costs from the prior general rate case?

A. The primary change has been the adoption of an hourly system simulation model as explained by Mr. Kalich. This model calculates the dispatch of Company resources in each hour of the proforma year, rather than a monthly average dispatch as was done with the dispatch model used in prior rate cases.

Power supply adjustments for known and measurable changes have been prepared using the same methods that have been used in prior general rate cases. Detailed work papers have been provided to the Commission coincident to this filing, that supports each of the proforma adjustments. A brief description of each adjustment is also included in Exhibit No. 10, Schedule 2.

Q. What is the overall change in normalized power supply costs compared to the prior general rate case?

A. Power supply expense has increased by approximately $11 million (Idaho) from the prior general rate case. This increase is primarily driven by reduced wholesale net revenues and an increase in fuel expense. Wholesale net revenue decreased by approximately $6 million (Idaho) due primarily to the restructuring of the capacity sale to Portland General Electric. The increase in fuel expense is driven by approximately $10.5 million (Idaho) increase in natural gas fuel expense due to the addition of the Coyote Springs 2 plant, which is offset by an approximately $6 million (Idaho) reduction in thermal fuel costs due mostly to the sale of the Centralia plant.

Short-Term Purchases and Sales

Q. How are the short-term market purchases (Account 555) and sales (Account 447) determined in the proforma?

A. Short-term market purchases and sales are an output of the AURORA model. They are the purchases and sales made to balance the system obligations and resources on an hourly basis. Mr. Kalich explains the derivation of the short-term sales revenue, and short-term purchase expense in detail in his testimony. Exhibit No. 10, Schedule 3 shows the proforma monthly short-term purchases and sales amounts and average price. These figure were taken from Mr. Kalich's Exhibit No. 11. As shown in Exhibit No. 10, Schedule 3, during the proforma period the Company is a net seller on an annual basis.

Long-Term Contracts

Q. What long-term contracts are included in the proforma?

A. There are five long-term or medium-term purchases and several small PURPA purchases and one pending wind energy purchase. The long-term purchase is the WNP-3 purchase from the Bonneville Power Administration (BPA). There are four medium-term purchases with a term of January 2004 through December 2006. There are approximately 14 average megawatts of PURPA and other small power purchases. In addition, a new wind power purchase that is expected to begin in early 2004 will provide approximately 10 average megawatts of energy. A brief summary of these contracts is provided in Exhibit No. 10, Schedule 2, and the detail of the costs for each is included in the workpapers that have been provided with this filing.

The Company has very few remaining long-term sales. One that remains is the Peaker capacity sale. This sale is the former Portland General Electric capacity sale that was monetized in 1998. The other two long-term sales of more substantial dollar volume include the Nichols pumping sale and the sale of reserves and control area services to Mirant for their half of Coyote Springs 2. With the Nichols sale, Avista sells power to the other owners of Colstrip units 3 and 4 to supply power to the pumps that supply water to the plant. The contract rate is the Dow Jones Mid Columbia index price. For the proforma, the revenue from the sale is based on the average market purchase and sales price developed by the AURORA model. The net effect is little, if any, impact on overall net power supply expense since the revenue from the sale offsets the cost created by the obligation. The advantage of this sale is that it reduces the transmission losses associated with wheeling Colstrip energy to Avista's system since some of Avista's Colstrip energy is "laid-off" at Colstrip to serve the Nichols pumping load.

Q. What is the impact on net power supply expense due to the expiration of most of the long-term sales contracts since the last general rate case?

A. The net expense increase due to the expiration of long-term wholesale contracts is approximately $15.7 million on a system basis. This is almost entirely due to the restructuring of the Portland General Electric (PGE) capacity sale. In the 1998 rate case the revenue from this sale was $18,288,000 ($10.16/kW/month) per year (system). With the restructuring of the contract the current revenue is $1,800,000 per year ($1/kW/month) (system), a revenue decrease of $16,488,000 per year on a system basis. Customers, however, have already received the full benefits of the original PGE capacity sale through the accelerated amortization of the payment Avista received for restructuring the contract (PGE Monetization). This accelerated amortization of the monetized contract payment was used to offset a portion of the PCA deferral balance. The amortization of the monetized contract payment ended December 2002.

The termination of other long-term energy sales had a relatively small impact on net power supply expense. Long-term wholesale energy sales reduced net power supply expense by approximately $750,000 (system) in the 1998 general rate case. The proforma in this filing does not include any net revenue from wholesale energy sales. It does include revenue from the sale of non-energy products, such as exchange capacity, generation reserves and load following services.

Thermal Fuel Expense

Q. How are thermal fuel expenses determined in the proforma?

A. Thermal fuel expenses include the Colstrip coal costs, Kettle Falls wood waste costs and natural gas expense for the Company's gas-fired resources including Coyote Springs 2, Rathdrum, Northeast, Boulder Park, and the Kettle Falls combustion turbine. Unit coal costs at Colstrip are based on the long-term coal supply and transportation agreements. Unit wood fuel costs at Kettle Falls are based on the multiple shorter-term contracts with fuel suppliers. Unit fuel costs for natural gas are based on forward market prices. Total fuel costs for each plant are based on the unit fuel cost and the plant's level of generation as determined by the AURORA model. Exhibit No. 10, Schedule 3 shows the proforma fuel costs by month for each plant.

Q. What is the change in Colstrip and Kettle Falls unit fuel costs?

A. The Colstrip per unit coal cost has increased from $10.27 per ton in the 2002 test year to $10.35 per ton in the proforma. The Kettle Falls per unit wood waste cost has increased from $12.77 per green ton in the test year to $13.82 per green ton in the proforma. The unit fuel costs increase at Kettle Falls is due in part to the increased demand for wood fuels and the increased distance from the plant for new suppliers.

Q. What is the change in natural gas fuel costs?

A. Natural gas fuel costs in 2002 did not include fuel consumption at Coyote Springs 2, which accounts for over $30 million of the total $35.6 million natural gas fuel expense in the proforma included in Account 547. Natural gas fuel expense will vary significantly based on both the cost of natural gas and the generation level of the natural gas fueled plants. In the proforma year, Coyote Springs 2 generates approximately 111 average megawatts (aMW) and the Company's other gas fueled plants combined, which are primarily peaking units, generate approximately 5 aMW.

Natural gas fuel unit costs are based on the forward market price of natural gas (as of December 10, 2003) as explained by Mr. Kalich. The average price of natural gas at Malin (gas price for Coyote Springs 2) during the proforma is $4.48 per dekatherm. Natural gas expenses also include the expense for natural gas transportation agreements used to serve the Coyote Springs 2 plant.

Q. Do proforma natural gas fuel expenses include the cost of the fixed price gas purchases made in 2001?

A. No. The proforma natural gas fuel expenses are based on the current forward market price of natural gas (as of December 10, 2003). The proforma net expense for natural gas purchased for, but not consumed for generation is normalized to $0 since the proforma assumes that all gas purchased will be consumed for generation and included in Account 547. Mr. Lafferty's testimony addresses the fixed price gas purchases made in 2001.

Transmission Expense

Q. What factors are driving the increase in transmission expense in the proforma?

A. Transmission expense in Account 565 increases by approximately $1.3 million (system) over the test year. The primary reason for the increased expense is additional amounts of transmission purchased in the proforma period. The amount of BPA transmission purchased to integrate generation is 343 MW, which includes 196 MW for Colstrip and 147 MW for Coyote Springs 2. Prior to operating Coyote Springs 2 the Company held 267 Megawatts of BPA transmission to integrate generation. Other changes include a 15 MW increase in transmission capacity to the California Oregon Border (COB) purchased from Portland General Electric, and an increase in short-term transmission expense for short-term system purchases and sales.

IV. PCA CALCULATIONS

Q. Is the Company proposing any changes to how the PCA deferral is calculated each month?

A. No. PCA entries will continue to be calculated in the same manner as the current calculations. The final order in this case will determine the new authorized level of power supply revenues and expenses used in the PCA calculation. There will be an additional line to accommodate the new power purchase from the Potlatch Lewiston facility, which I will discuss later in my testimony.

Q. Will the PCA continue to include the revenues and expenses from purchases and sales of transactions related to the acquisition of natural gas for thermal generation?

A. Yes. The Company will likely continue to fix the price in advance on some portion of natural gas necessary to run thermal generation. There will also be instances where the Company later, because of a change in market electric and natural gas prices, sells the gas and purchases electricity. These types of transactions may lead to a net gain or loss on the sale of the natural gas that will be recorded as a separate line in the PCA. The objective of these transactions is to provide some stability over time to the cost of natural gas to fuel these generators, while also having the opportunity to make the most economic decision when the time comes to either burn the gas or sell the gas and purchase electricity. The revenue and expenses from these transactions will be recorded in Account 557 (Other Power Supply Expenses) for the cost of the natural gas purchased and Account 456 (Other Electric Revenues) for the revenue from the natural gas sales.

Q. How will changes in the costs associated with Potlatch's Lewiston generation be included in the PCA?

A. The Potlatch purchase expense will be a separate line item in the PCA calculation. Changes in the Potlatch purchase expense will be included in the PCA at 100 percent of the change. A change in Potlatch Lewiston corresponding to the change in Potlatch generation will also be included at the 100 percent level in the retail revenue credit. Additional Potlatch load changes, not corresponding to their generation, will be included at the 90 percent level in the retail revenue credit within the PCA. The proposed base level for the Potlatch power purchase expense and the Potlatch revenue corresponding to their generation is shown in Exhibit 10, Schedule 4.

Q. Will there be any change in how the retail revenue adjustment is calculated in the PCA?

A. No. The only changes that will occur will be in the new authorized level of retail sales and the incremental cost of power that will be approved in this case. The Company has proposed that the authorized retail sales will be based on the weather-adjusted 2002 sales used in this case. The proposed base level of retail sales is shown in Exhibit 10, Schedule 4. The incremental cost of power is $36.38/MWh, which is the weighted average price of Avista's short-term market sales and purchases as determined by the AURORA model.

Q. What is the new authorized level of power supply expense proposed by the Company for the PCA?

A. The new authorized level of annual power supply expense is $71,456,998. This is the sum of Accounts 555 (Purchased Power), 501 (Thermal Fuel), and 547 (Fuel) less Account 447 (Sale for Resale). The current level of authorized power supply expense is $57,866,430. The increase in expense is $13,590,568 on a system basis. The proforma-authorized expense does not include the cost of power purchased from Potlatch. That expense will be included as a separate non-system (100% allocated to Idaho) expense in the PCA and changes to that expense will be included at the 100 percent level in the PCA deferral calculation. The proposed base level of net power supply expense is shown in Exhibit 10, Schedule 4.

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

A. Yes.