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IDAHO PUBLIC
UTILITIES COMMISSION

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE POWER COST	)	CASE NO. AVU-E-20-07
ADJUSTMENT (PCA) ANNUAL RATE	)	
ADJUSTMENT FILING OF AVISTA	)	DIRECT TESTIMONY OF
CORPORATION	)	SCOTT C. REID

FOR AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Scott C. Reid. My business address is 1411 E. Mission Avenue, Spokane, Washington, and I am employed by the Company as a Wholesale Marketing Manager in the Energy Resources department.

Q. What is your educational background?

A. I am a 1988 graduate of the University of Puget Sound with a Bachelor of Arts in Business Administration. I obtained a Master of Business Administration from the University of Oregon in 1996.

Q. How long have you been employed by the Company and what are your duties as a Wholesale Marketing Manager?

A. I started working for Avista in 1998 as a Business Analyst. After eight years in the Financial Planning and Analysis department and three years in the Regulatory Affairs department, I joined the Energy Resources department in 2009. My primary responsibilities focus on analytical and decision support for Energy Resources' operations.

Q. Have you previously filed testimony in annual Power Cost Adjustment proceedings?

A. No, I have not. This is the first filing where I am sponsoring testimony. William G. Johnson, who previously filed testimony in these proceedings, will retire effective August 1, 2020.

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

A. My testimony gives an overview of power supply operations and provides a summary of the factors contributing to the power cost deferrals during the July 2019 through June 2020 review period (review period).

Q. Are other witnesses sponsoring testimony on behalf of Avista?

A. Yes. Company witness Ms. Brandon provides testimony concerning the monthly accounting entries and account balances related to the Power Cost Adjustment for the twelve-months ended June 30, 2020.

Q. Are you sponsoring any work papers and supporting documentation to be introduced in this proceeding?

A. Yes. Detailed work papers supporting the tables and other calculations in my testimony have been provided in electronic format to the Commission, and other parties coincident to this filing. The Company has also provided supporting documentation, including details of all term natural gas and electricity transactions that flowed during the review period, and daily position reports that show, among other things, forward price curves. Copies of long-term power contracts that the Company entered into during the review period have also been provided.

II. OVERVIEW OF POWER SUPPLY OPERATIONS

Q. How does Avista, generally, manage its power supply resources?

A. Avista Utilities conducts electric planning, procurement, sales and power resource management activities to ensure an adequate supply of electricity to serve customer and other load obligations, as well as to optimize our generation and transmission resources. As one can imagine, numerous variables affect Short-Term power supply. As such we employ the Energy Resources Risk Policy to recognize and actively manage the interaction and dynamics among these variables by establishing processes for future load and obligation estimation, resource estimation, and management of the expected net surplus or deficit Short-Term position.

It is understood that many factors cause loads to differ from estimates. It is also understood that each of Avista's generating resources has inherent variability because of streamflow and water storage conditions (for hydroelectric plants), mechanical limitations, transmission constraints, fuel availability and conditions, ambient conditions, environmental and permit conditions and other factors.

The Energy Resources department, of which I am a member of, is responsible for fuel management, optimizing the use of electric resources including wholesale power contracts, obtaining and dispatching power resources to meet load obligations and provide good stewardship of electric resources.

Energy resource planning involves a number of estimates. Actual loads rarely match forward estimates precisely. The net surplus or deficit requires constant attention and its variability dictates that flexibility be maintained at all times. It is necessary to buy and sell energy (or financially equivalent derivative transactions) in hourly, daily, monthly and longer increments, and adjust dispatch plans to meet prevailing conditions. As such, we may use any electricity and fuel transactions that are authorized in our Risk Policy to the extent that they relate directly or indirectly to serving Avista Utilities electric loads or obligations and optimizing the value of Avista Utilities energy resources.

Q. What types of transactions will Avista enter in to, as detailed and authorized in the Company's Risk Policy?

A. The following are example types of transactions permitted in the context of managing Avista's energy resources and serving the Company's obligations in the Short-Term and Immediate-Term time horizons:

- Scheduling and dispatching energy resource facilities owned or controlled by Avista.
- Transactions with other parties for physical delivery of capacity or energy, including fixed price and indexed or formula priced transactions.
- Ancillary services, such as reserves, load-following, generation imbalance and others.
- Transportation, transmission, storage and capacity obligations and rights.
- Bilateral forward transactions with approved counterparties.
- Futures contracts traded on an established commodities exchange.
- Swap agreements as a tool for fixed price financial hedges.
- Transactions that allow Avista Utilities to buy or sell electricity or natural gas at Avista's discretion.
- Exchange agreements (forward commodity agreements expected to be settled with return of the commodity rather than cash, either with or without associated settlement prices).
- Fuel (supply, delivery, storage, excess fuel disposition) related to specific electric generating facilities in which Avista Utilities has an ownership or contractual interest including natural gas, coal and biomass (wood waste) and related emission allowances.
- Streamflow and water storage rights and benefits related to Avista Utilities owned or contracted hydroelectric generation stations including coordination of the related river systems.

Q. How does Avista optimize its energy resources for the benefit of its customers?

A. Avista optimizes its energy resources in a number of ways. Electric resource optimization involves choices among several variables. We assess these variables to select and execute an appropriate mix for Short-Term and Intermediate-Term objectives. Intra-month activity during the prompt month to serve loads, optimize resources, and participate in the electric market is reported after-the-fact in the daily position report. Electric optimization variables include:

- Scheduling and dispatching of available Avista's generating units as indicated by relevant plant parameters.
- Buying fuel to operate a generating facility or selling fuel already available to decrease or eliminate generation from a unit.
- Storing or using water for hydroelectric generation that maximizes expected generation value and arranging for water from or for other hydroelectric plants in the coordinated river system.
- Buying or selling or exchanging electricity in the wholesale market from/to other utilities, power marketers, or independent power producers, including displacing purchases and sales available to the Avista Utilities balancing area.
- Buying or selling financial contracts that hedge electric purchase or sale prices and open positions.
- Obtaining transmission rights as may be needed to deliver or receive output to or from any Avista generation source or any market and selling surplus transmission rights.
- Buying and selling the gas basis spread based on gas transport contract rights.

Q. Does the Company have an active hedging program?

A. Yes. The Company employs a Power Supply Hedge Requirements Report tool (PSHRR). The PSHRR is an analytical tool to guide power supply hedging decisions in the Short-Term forward period. It provides a process to systematically reduce open positions with forward transactions by buying for expected shortages and selling expected surpluses. An "open" position for this purpose is the forecasted monthly financial position that is not covered by fixed price physical or financial transactions, i.e., the surplus or deficit that is subject to price risk. The plan provides guidance, but may not be followed rigidly when management judgment or market conditions warrant other actions, no action, or simply a delay in taking action.

III. SUMMARY OF DEFERRED POWER SUPPLY COSTS

Q. What were the changes in power costs during the PCA review period?

A. During the review period actual net power costs were higher than the authorized net power costs for the Idaho jurisdiction by $1,153,941. After taking into consideration the 90% allowable deferral percent, the total is $1,038,548.

Q. Please summarize why actual power supply expense was lower than the authorized level during the review period?

A. Table No. 1 below shows the primary factors impacting power supply expense during the review period:

<u>Table No. 1:</u>

Factors Contributing to Increased Power Supply Expense
July 2019 - June 2020, Idaho Allocation

1	Change in Hydro Generation	$ 2,611,587
2	Change in Gas Generation and Natural Gas Prices	(6,097,200)
3	Change in Colstrip & Kettle Falls Generation and Fuel Expense	323,694
4	Change in Net Power Purchase Expense	398,215
5	Change in Net Transmission Expense (Expense - Revenue)	(931,775)
6	Change in Palouse Wind PPA Net Expense	4,960,433
7	Change in Retail Loads (Power Cost Change less Retail Revenue Adj)	7,135
8	Change in Misc Expense	(118,148)
	Actual minus Authorized	1,153,941
	@ 90% Allowed	**$ 1,038,548**

Q. Please describe the contribution of each item shown above in Table No. 1 to the increase in net power supply expenses.

A. Provided below is a summary of the factors that, added together, resulted in an increase in power supply expenses for the review period (the "Item" number references back to Table No. 1):

Item No. 1 Change in Hydro Generation ($2,611,587 surcharge direction). One factor increasing power supply expense was reduced hydro generation of 48 aMW below the authorized level. Hydro generation at Company-owned plants accounted for the majority of the variance at 46 aMW, with the remaining 2 aMW variance attributed to lower than authorized generation from the Mid-Columbia contracted hydro plants. Hydro generation is weather dependent and difficult to predict.

Item No. 2 Change in Gas Generation and Natural Gas Prices ($6,097,200 rebate direction). Lower natural gas prices and increased revenue from gas-fired generation resulted in the largest cost reduction ($6.1 million) of any of the items when compared to authorized. Gas-fired plants generated 33 aMW more than authorized, resulting in $4.3 million (Idaho allocation) of increased revenue from sales at the Mid-Columbia ("Mid-C") electricity trading hub. The increased generation necessitated more natural gas purchases, yet overall commodity expense was lower than authorized by $1.6 million because of lower than authorized natural gas prices.

The AECO natural gas trading hub continued to experience low prices during the review period caused by over-supply conditions partly due to reduced demand from the eastern United States. Prices at the Malin natural gas trading hub remained relatively higher, so Avista was able to capture the price spreads between AECO and Malin by utilizing its firm natural gas transportation contracts to purchase natural gas at a low price at AECO, and sell natural gas into the higher-priced Malin market, thereby locking in a favorable benefit for our customers.

As a result, the effective average transacted natural gas cost was \$1.72/dekatherm compared to \$1.92/dekatherm in authorized expense.

Item No. 3 Change in Colstrip and Kettle Falls Generation (\$323,694 surcharge direction). The change in the value of Colstrip and Kettle Falls is a function of the change in generation multiplied by the market price of power, netted against the change in fuel expense. The value of Kettle Falls was \$25,171 higher than the authorized level (rebate direction), and the value of Colstrip was \$348,864 lower than the authorized level (surcharge direction), for a net surcharge of \$323,694. Kettle Falls generated 2 aMW above the authorized level. Colstrip generated 8 aMW below the authorized level.

Item No. 4 Change in Net Power Purchase Expense: (\$398,215 surcharge direction). This category is a function of the authorized level of short-term purchases and sales times the difference in actual versus authorized market prices, plus any incidental changes in contract expenses not related to changes in generation. Effectively, when Avista was a net buyer, power prices deviated from the authorized prices to a greater degree than prices deviated from the authorized level when Avista was a net seller.

Item No. 5 Change in Net Transmission Expense (\$931,775 rebate direction). Net transmission expense was below the authorized level primarily due to higher third-party transmission revenues. Transmission expense was slightly lower than the authorized level and third-party transmission revenue was much higher than the authorized level. Third-party transmission revenues result from increased purchases or sales from other regional entities utilizing our transmission system. Fluctuations in short-term transmission sales are partially a function of other utilities' load/resource balance and whether they are sellers or buyers.

Item No. 6 Change in Palouse Wind Net Expense ($4,960,433 surcharge direction). Because the Palouse Wind power purchase agreement is not included in base rates in Idaho, the increase in net expense in the PCA is a function of the actual hourly generation of the plant times the contract price offset by the hourly market value of the power generated. For the year, Palouse Wind generated 38.8 aMW. The market value of the generation was less than the power purchase expense, resulting in a surcharge direction impact of the Palouse Wind contract.

Item No. 7 Change in Retail Loads ($7,135 surcharge direction). The impact of the change in retail loads is the net of the deviation in actual load versus the authorized level times the market price of power netted against the retail revenue adjustment. For the review period, Idaho retail sales were 2 aMW below the authorized level. In periods when load and retail sales were lower (primarily July and December), prices were higher than the Load Change Adjustment Rate, which increased expense. Additional information regarding the Load Change Adjustment Rate has been provided later in my testimony.

Item No. 8 Change in Misc. Expense ($118,148 rebate direction). Miscellaneous Expense consists of broker fees, California Independent System Operator (CAISO) fees, and the Montana Invasive Species expenses. Broker fees and CAISO fees, which are tracked in the PCA but not included in authorized base rates, totaled $165,808 in the surcharge direction. Montana Invasive Species expenses, tracked in the PCA but not included in authorized base rates until December 2019 (Case No. AVU-E-19-04), exceeded authorized by $670,943 in the surcharge direction. Finally, REC Revenue was higher than authorized, for a rebate of $1,168,098.[1]

[1] This is inclusive of Clearwater Paper RECs sold to a third party in which Clearwater Paper receives 90 percent of the net proceeds and the remaining 10 percent is included as REC revenue in the PCA.

Summary. Power supply expense was higher than the authorized level by $1,153,941 (Idaho allocation). The increase in power supply expense was primarily due to Palouse Wind net expense and reduced hydro generation, offset by lower AECO gas acquisition prices, increased gas-fired generation, and lower than authorized net transmission expenses. The Company is providing work papers supporting all impacts listed in Table No. 1 and described in more detail above.

IV. NEW LONG-TERM CONTRACTS ENTERED INTO DURING REVIEW PERIOD

Q. Please provide a brief description of new long-term contracts that the Company entered into during the review period.

A. The Company entered into five long-term power purchase PURPA contracts during the review period. In October 2019, the Company renewed a contract for the purchase of the Upriver hydroelectric facility output owned by the City of Spokane. In December 2019, the Company renewed a contract for the purchase of the Stimson wood-fired facility output in Plummer Idaho. In March 2020, the Company renewed two hydroelectric purchase contracts, one with Meyers Falls and the other with Sheep Creek. In May 2020, the Company originated a contract for the purchase of the SIERR rooftop solar facility output in downtown Spokane. Copies of these contracts have been provided in monthly ERM reports.

V. SUPPORTING DOCUMENTATION

Q. Please provide a brief overview of the documentation provided by the Company in this filing.

A. The Company maintains a number of documents that record relevant factors considered at the time of a transaction. The following is a list of documents that are maintained and that have been provided in electronic format with this filing:

- Natural Gas/Electric Transaction Records: These documents record the key details of the price, terms and conditions of a transaction. As part of Avista's workpapers accompanying this filing the Company has provided a confidential worksheet showing each natural gas and electric term (balance of the month or longer) transaction during the review period, including all key transaction details such as trade date, delivery period, price, volume and counter-party. Additional information can be provided, upon request, for any of these transactions.
- Position Reports: These daily reports for each trading day in the review period provide a summary of transactions and plant generation and the Company's net average system position in future periods. The Daily Position Reports also contain forward electric and natural gas prices.

VI. OVERVIEW OF DEFERRAL CALCULATIONS

Q. Please provide an overview of the deferral calculation methodology.

A. Energy cost deferrals under the PCA are calculated each month by subtracting base net power supply expense from actual net power supply expense to determine the change in net power supply expense. The base levels for the review period result from the power supply revenues and expenses approved by the Commission in Case No. AVU-E-17-01 for July 2019 through November 2019, and in Case No. AVU-E-19-04 for December 2019 through June 2020. The methodology compares the actual and base amounts each month in FERC accounts

555 (Purchased Power), 501 (Thermal Fuel), 547 (Fuel) and 447 (Sales for Resale) to compute the change in power supply expense. These four FERC accounts comprise the Company's major power supply cost/revenue accounts. The ERM also includes changes in Accounts 565 (transmission expense), and 456 (third-party transmission revenue).

In addition, actual expense and revenue for natural gas not burned is included as natural gas sale revenue under Account 456 (revenue) and purchase expense under Account 557 (expense). This would include benefits and costs related to optimizing the value of natural gas turbines and power supply's natural gas transportation contracts. All expenses are recorded in accordance with Generally Accepted Accounting Principles and FERC's Uniform System of Accounts.

The total change in net expense under the ERM is multiplied by Idaho's share of the Production/Transmission Ratio (PT Ratio) approved in association with base net power supply expense. Change in Idaho retail sales is then multiplied by the Load Change Adjustment Rate (LCAR) and added or subtracted from the change in power supply expense to calculate the total power expense change. 90 percent of the change in power expense is deferred and 10 percent is retained by the Company.

Q. Please explain how the load change adjustment is calculated in the PCA.

A. The PCA includes a load change adjustment to reflect the change in power production and transmission expense recovered through base retail revenues, related to changes in retail load. The Load Change Adjustment Rate calculation is based on the energy classified production and transmission costs included in the Company's general rate case. The LCAR revenue adjustment for July through November 2019 was \$24.84/MWh and \$22.00/MWh beginning December 2019.

The monthly load change adjustment in the PCA is computed by multiplying the retail revenue adjustment rate times the difference between actual and authorized monthly retail Megawatt-hour sales. If actual Megawatt-hour sales are greater than base, the retail revenue adjustment will result in a credit to the PCA deferral (reduces power supply costs). If actual Megawatt-hour sales are less than base, the retail revenue adjustment will result in a debit to the PCA deferral (increases power supply costs).

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

A. Yes.