BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-21____

DIRECT TESTIMONY OF

ANNETTE M. BRANDON

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Annette M. Brandon. I am employed by Avista Corporation as a Wholesale Contract Manager in the Power Supply Department. My business address is 1411 East Mission, Spokane, Washington.

Q. Would you please describe your educational background and professional experience?

A. Yes. I am a 2002 graduate of Eastern Washington University with a Bachelor of Arts degree in Business Administration – Professional Accounting. I started with Avista in January 1999 as a Budget Analyst in the Company's Transmission department. I spent three years in the Company's Tax Department before moving to Resource Accounting for the next eight years. I joined the Regulatory Affairs department as a Regulatory Analyst in 2012 and was promoted to Manager Regulatory Affairs in 2013. My primary responsibilities in Regulatory Affairs related to oversight of the purchase gas cost adjustment filings, Power Supply including general rate case adjustments, monthly/annual reporting, key contact for the Company's compensation and benefits programs, and revenue requirement for Oregon. I moved to my current role of Wholesale Contracts Manager in the Power Supply Department in August 2020. In this role, my responsibilities are related to the ERM and PCA annual filings and support for development of authorized power supply in General Rate Case proceedings. In addition, I manage the Company's transmission contracts, Request for Proposals processes and currently am the lead for Washington's Clean Energy Implementation Plan.

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

A. My testimony will provide an overview of the history of the Energy Recovery Mechanism (ERM) and provide a summary of the factors contributing to the power cost deferrals during the 2020 calendar year review period. I provide an overview of the documentation the Company has provided in work papers, which the Company has agreed to provide in the ERM Settlement Stipulation approved and adopted in Docket No. UE-030751. My testimony will also briefly describe how the power cost deferrals are calculated.

Q. What was the ERM deferral amount in 2020?

A. For the 2020 calendar year, actual net power costs were less than authorized net power costs for the Washington jurisdiction by $17,479,519 (excluding interest). The deferral in the customer rebate direction for 2020 amounted to $11,231,567. Pursuant to the mechanics of the ERM, the Company retained $6,247,952 in 2020.

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

A. Yes. Company witness Ms. Schultz provides testimony concerning the monthly deferral entries and the deferral balance.

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

A. Yes. I am sponsoring Exh. AMB-2, which are four pages from the Company's December 2020 Monthly Power Cost Deferral Report previously provided to the Commission. These four pages show the deferral calculations for the period January 2020 through December 2020. Page 1 of Exh. AMB-2 shows the calculation of the deferral, pages 2 through 3 show the actual expenses and revenues, and page 4 shows the retail revenue adjustment. 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.

II. OVERVIEW AND HISTORY OF ERM

Q. Would you please explain the history of the ERM and the annual filing requirement?

A. Yes. The ERM was approved by the Commission's Fifth Supplemental Order in Docket No. UE-011595, dated June 18, 2002, and was implemented on July 1, 2002. That Order approved and adopted a Settlement Stipulation (UE-011595 Stipulation) that explained the mechanism and reporting requirements. Pursuant to the UE-011595 Stipulation, the Company is required to make an annual filing on or before April 1st of each year. This filing provides an opportunity for the Commission Staff, and other interested parties, to review the prudence of the ERM deferral entries for the prior calendar year. Interested parties are to be provided a 90-day review period, ending June 30th of each year to review the deferral information. The 90-day review period may be extended by agreement of the parties participating in the review, or by Commission order.

Avista's first Annual ERM Filing covered the six-month period of July 1, 2002 through December 31, 2002. Avista has made ERM annual review filings for each subsequent calendar year period. Last year's annual ERM filing covering the 2019 calendar year was filed March 31, 2020 in Docket No. UE-200291.

III. 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 assure 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.

Energy Resources, 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. Variability of resources is inherent because of weather, streamflow and wind conditions, physical and operational limitations and prevailing market-driven economics related to power and fuel.

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 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, 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 natural gas basis spread based on natural 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 analytic 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.

IV. SUMMARY OF DEFERRED POWER SUPPLY COSTS

Q. What were the changes in power costs, the amounts deferred, and the amounts absorbed by the Company during 2020?

A. During 2020 actual net power costs were lower than the authorized net power costs for the Washington jurisdiction by $17,479,519. Under the mechanics of the ERM, the first $4.0 million of net power supply costs above or below the authorized level is absorbed by the Company. When actual costs exceed authorized costs by more than $4 million (surcharge direction), 50% of the next $6 million of difference in costs is absorbed by the Company, and 50% is deferred for future recovery from customers. When actual costs are less than authorized costs (rebate direction), as it the case with this filing, 25% of the next $6 million of difference above the $4 million dead band is absorbed by the Company, and 75% is deferred for rebate to customers. If the difference in costs exceeds $10 million, either in the surcharge or rebate direction, 10% of the amount above $10 million is absorbed by the Company, and 90% is deferred. Pursuant to the mechanics of the ERM, the Company retained $6,247,952 in 2020.

The deferral in the customer rebate direction for 2020 amounted to $11,231,567 (excluding interest). The <u>total</u> ERM customer deferral for 2020 amounted to $11,383,248 which consists of the following four items:

1. Rebate amount of $4,500,000 related to 75% of the net power costs residing in the $4.0 million to $10.0 million sharing band

2. Rebate amount of $6,731,567 related to the 90% of the net power costs residing in the Over $10 million sharing band.
3. The net effect of the Solar Select Program for 2020 for a surcharge of $57,572.
4. Rebate amount of $209,253 related to interest.

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 2020:

Table No. 1 – Factors Contributing To Decreased Power Supply Expense in 2020

	Factors Contributing to Decreased Power Supply Expense 2020 - Washington Allocation		
			WA
1	Change in Hydro Generation		6,127,210
2	Change in Gas Generation and Natural Gas Prices		-$13,536,940
3	Change in Colstrip & Kettle Falls Generation and Fuel Expense		$3,188,988
4	Change in Net Power Purchase Expense		-$11,344,680
5	Change in Net Transmission Expense (Expense - Revenues)		-$3,563,857
6	Change in Wind Net Expense		$938,600
7	Change in Retail Loads (Power Cost Change less Retail Revenue Adjustment)		$646,611
8	Change in Power Product Sales and Misc Expense		$64,548
	Total Expense Below the Authorized Level		-$17,479,520
	Notes:		
	1 Hydro generation was 30 aMW below the authorized level.		
	2 Includes change in gas generation net value and gas transport value.		
	3 Includes change in generation and fuel expense.		
	4 Decreased expense due to increased sales in certain months.		
	5 Increased transmission revenue and decreased expense.		
	6 Includes change in generation and purchase expense.		
	7 Loads were down contributing to a surcharge variance		
	8 Revenue from sale of additional ancillary products.		

Q. Based on the information provided in Table No. 1 above, the primary contributor to the decrease in power supply expense in 2020 was related to changes in *Line 2 Gas Generation and Natural Gas Prices ($13,536,940 in the rebate direction)*. Would you please provide additional information related to this contributing factor?

A. Yes. For 2020, higher natural gas generation and lower natural gas prices reduced power supply expense by approximately $13.5 million below the authorized level. The primary contributor to this expense reduction was continued low natural gas prices at each of the natural gas trading hubs relative to the authorized levels. The average delivered natural gas cost was $1.72/dekatherm in 2020 compared to $2.33/dekatherm in the authorized. In addition, Avista's natural gas generation facilities generated 34 aMW greater than the authorized level in 2020 which provided the Company with an opportunity to take advantage of market opportunities by purchasing lower cost natural gas, generating electricity from it, and selling the generated electricity at the Mid-Columbia ("Mid-C") electricity trading hub, locking in favorable spreads for customers.

Q. The second highest contributor to the 2020 rebate deferral is related to *Line No. 4 Change in Net Power Purchase Expense ($11,344,680 in the rebate direction)*. Please describe the factors which contributed to this amount?

A. This category is a function of the authorized level of short-term purchases and sales times the difference in actual market prices versus authorized prices, plus any incidental changes in contract expenses not related to changes in generation. Effectively, when Avista was a net seller, power prices deviated from the authorized prices to a greater degree than prices deviated from the authorized level when Avista was a net purchaser. This category also captures the lag in actual long-term contract costs in 2020 being higher than older authorized costs.

Q. Please describe the components which contributed the remaining variance in power supply expense in 2020.

A. Provided below is a summary of the other factors that, coupled together, resulted in the remaining variance in power supply expenses for 2020 (the "Item" number references back to Table No. 1):

Item No. 1 Change in Hydro Generation ($6,127,210 surcharge direction). The primary factor in the surcharge direction for 2020 was hydro generation of 30 aMW below the authorized level. Avista-owned generation accounted for 22 aMW of the variance with the remaining variance being the hydro generation from the Mid-Columbia projects. As with wholesale electric and natural gas prices, hydro generation is very weather dependent and difficult to predict. In 2020, snowpack was healthy in January and February, but low temperatures in March and April caused a late runoff and led to less generation than authorized.

Item No. 3 Change in Colstrip and Kettle Falls Generation ($3,188,988 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 $433,709 lower than the authorized level (surcharge direction), while the value of Colstrip was $2,755,279 lower than the authorized level (surcharge direction). For both plants, fuel costs were higher than the authorized level. Kettle Falls hog fuel costs have been escalating due to market conditions. For Colstrip, Avista entered into a new coal contract beginning in January 2020 with higher pricing than authorized levels. Kettle Falls and Colstrip generated 5 aMW and 24 aMW below their respective authorized level.

<u>Item No. 5 Change in Net Transmission Expense ($3,563,857 rebate direction</u>). Transmission expense was 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 Avista's transmission system.

<u>Item No. 6 Change in Wind Net Expense ($938,600 surcharge direction)</u>. The increase in net Wind power purchase expense was a function of the deviation of the actual hourly generation pattern versus the authorized generation pattern. For 2020, Palouse Wind generated 2 aMW above the authorized level, and Rattlesnake Wind generated 4 aMW above the authorized level. This typically pushes the ERM in the surcharge direction since the contract price of the power purchase normally exceeds the value of the power.

<u>Item No. 7 Change in Retail Loads ($646,611 surcharge direction)</u>. The impact of the change in retail loads is the net of the deviation in actual retail load versus the authorized level times the market price of power netted against the retail revenue adjustment. For 2020, Washington retail sales were 34 aMW below the authorized level.

<u>Item No. 8 Change in Power Product Sales and Misc. Expense ($64,548 surcharge direction)</u>. This category is comprised of broker fees, CAISO transaction fees, and other miscellaneous small charges. The primary rebate variance for 2020 was related to CAISO transaction charges which were not included in the authorized.

In summary, changes in natural gas generation and natural gas prices resulted in $13.5 million of reduced expense, combined with selling into higher-priced markets resulted an additional $11.3 million account for approximately $24.9 million of total reduced expense. This was offset by unfavorable hydro conditions of $6.1 million and higher costs related to Colstrip and Kettle falls fuel costs for $3.2 million. The result is an overall decrease in ERM-related expenses of approximately $17.5 million. The Company is providing work papers supporting all impacts listed in Table No. 1 and described in more detail above.

Q. Are there any other factors which may affect the Power Supply Deferral for 2020?

A. Yes. In 2020 the Company tracked the revenues and expenses associated with the Solar Select Program approved by this Commission in Docket UE-180102. The net margin associated with this program reduced the ERM deferral rebate by approximately $57,000. As described by Ms. Schultz, prudency of this amount will be determined as part of this filing. Once prudency is determined, this amount will be included in the overall deferral balance and refunded to customers at 100%.

V. NEW LONG-TERM CONTRACTS ENTERED INTO IN 2020

Q. Please provide a brief description of new long-term contracts that the Company executed during 2020.

A. The Company entered into three long-term power purchase contracts in 2020. In March, the Company entered into two five (5) MW PURPA contracts for fifteen years with Sheep Creek Hydro and Hydro Technology System. In addition, a PURPA for 5 MW was entered into with Great Northern LLC. Copies of these contracts have been provided in my workpapers.

Q. Are any long-term contracts subject to the limitation for inclusion in the ERM that was part of the settlement in Docket UE-060181?

A. No. The 2006 Settlement Agreement in Docket No. UE-060181 regarding the continuation of the ERM included limitations on cost recovery for new or renewed contracts that are greater than 50 MW and have more than a two-year term. No new long-term contracts that were in effect during the 2020 review period are subject to limitations on cost recovery.

VI. THERMAL RESOURCE AVAILABILITY

Q. Please describe the availability factor requirement and actual availability factors for the Company's major thermal plants, specifically Kettle Falls, Colstrip and Coyote Spring 2 and Lancaster.

A. The 2006 Settlement Agreement in Docket No. UE-060181 regarding the continuation of the ERM included potential limitation of the recovery of fixed costs associated with Kettle Falls, Colstrip and Coyote Springs 2 generating plants when the plants fail to meet a 70% availability factor during the ERM review period. The Equivalent Availability Factors[1] for the Company's thermal plants during 2020 are shown in Table No. 2 below.

Table No. 2 - 2020 Thermal Generation Plant Availability Factors

2020 Thermal Generation Plan Availability Factors	
Colstrip	74.11%
Coyote Springs 2	84.14%
Kettle Falls	78.54%
Lancaster	91.79%

[1] Note "equivalent availability factor" is an industry-standard calculation: Total available hours minus outages (forced and planned) divided by Total available hours. This is not meant to represent the North America Electric Reliability Corporation (NERC) required Generating Availability Data System (GADS) calculation which is done within NERC's system for conventional generating units that are 20 MW and larger.

VII. 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 work papers 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 2020, 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 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.

VIII. OVERVIEW OF DEFERRAL CALCULATIONS

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

A. Energy cost deferrals under the ERM 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 2020 result from the power supply revenues and expenses approved by the Commission in Docket No. UE-170485. 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), 456 (third-party transmission revenue), and broker fees.

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 Washington's share of the Production/Transmission Ratio (PT Ratio) approved in association with base net power supply expense. Change in Washington retail sales is then multiplied by the Retail Revenue Adjustment Rate and added or subtracted from the change in power supply expense to calculate the total power cost change. The total power cost change is accumulated during the calendar year until the dead band of $4.0 million is reached. Fifty percent of power cost increases, or 75 percent of the decreases, between $4.0 million and $10.0 million, and ninety percent of the power cost increases or decreases in excess of $10.0 million are recorded as the power cost deferrals and added to the power cost deferral-balancing account, as illustrated in Table No. 3 below:

Table No. 3: ERM Deadbands and Sharing Bands

Annual Power supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
+/- $0 - $4 million	0%	100%
+ between $4 million - $10 million	50%	50%
- between $4 million - $10 million	75%	25%
+/- excess over $10 million	90%	10%

Q. Please explain how the retail revenue adjustment is determined in the ERM.

A. The ERM includes a retail revenue adjustment to reflect the change in power production and transmission expense recovered through base retail revenues, related to changes in retail load. The retail revenue adjustment rate calculation is based on the average rate of the power supply expense related FERC accounts included in the Company's general rate case. The retail revenue adjustment in 2020 was $18.11/MWh.

The monthly retail revenue adjustment in the ERM 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 ERM 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 ERM deferral (increases power supply costs).

Q. What ERM calculations are provided to the Commission and other parties?

A. The Company provides to the Commission and other parties a monthly power cost deferral report showing, among other things, the calculation of the monthly deferral amount, the actual power supply expenses and revenues for the month, and the retail revenue adjustment. These pages from the December 2020 deferral report are included as Exh. AMB-2. The December 2020 deferral report pages show all of the months, January through December of 2020. Please note these pages represent a subset of the December 2020 Report provided as Exh. AMB-2.

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

A. Yes.