BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-18____

DIRECT TESTIMONY OF

WILLIAM G. JOHNSON

REPRESENTING AVISTA CORPORATION

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 Wholesale Marketing Manager in the Energy Resources Department.

Q. What is your educational background?

A. I am a 1981 graduate of the University of Montana 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 Wholesale Marketing Manager?

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 power contract origination and management and power supply regulatory issues.

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 2017 calendar year review period. I provide an overview of the documentation the Company has provided in workpapers, 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.

For the 2017 calendar year, actual net power costs were less than authorized net power costs for the Washington jurisdiction by $6,219,740. The deferral in the rebate direction for 2017 amounted to $1,664,805 (excluding interest). The Company retained $4,554,935 in reduced net power costs in 2017. The deferral rebate is primarily due to lower wholesale power prices and optimization of the Company's natural gas-fired facilities. Power costs were also lower due to lower coal and wood fuel costs, increased transmission revenues and a one-time prior period adjustment.

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

A. Yes. Company witness Ms. Brandon 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 Exhibit No.___ (WGJ-2), which includes four pages from December 2017's Monthly Power Cost Deferral Report previously provided to the Commission. These pages show the deferral calculations for the period January 2017 through December 2017. Page 1 of Exhibit No.___(WGJ-2) shows the calculation of the deferral, pages 1 through 4 show the actual expenses and revenues, and page 5 shows the retail revenue adjustment. Detailed workpapers, which are described later 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. The annual ERM filing covering the 2016 calendar year was filed March 30, 2017 in Docket No. UE-170218. Order 01 was issued in that docket on June 29, 2017, and the Commission found that the power cost deferrals for 2016 were properly calculated and recorded.

III. 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 2017?

A. During 2017 actual net power costs were lower than the authorized net power costs for the Washington jurisdiction by $6,219,740. Under 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 is 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.

The deferral for 2017 amounted to $1,684,801, which consists of the following two items:

1. Rebate amount of $1,664,805 related to 75% of the net power costs residing in the $4.0 million to $10.0 million sharing band.
2. Rebate amount of $19,996 related to interest.

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

A. In summarizing 2017, decreased power supply expenses resulted primarily from lower wholesale power prices and, optimization of the Company's natural gas-fired generating facilities. The actual average natural gas price was $2.59/dth compared to the authorized price of $2.77/dth. The average short-term physical power purchase price was $18.94/MWh compared to an authorized price of $29.00/MWh. For the year, hydro generation was 11.8 aMW above the authorized level. Table No. 1 below shows the primary factors impacting power supply expense during 2017:

Table No. 1:

	Factors Contributing to Decreased Power Supply Expense 2017 - Washington Allocation	
1	Change in Avista Owned Hydro Generation	$1,357,412
2	Change in Gas Generation and Natural Gas and Power Prices	-$8,343,471
3	Change in Colstrip & Kettle Falls Generation and Fuel Expense	-$2,629,783
4	Change in Mid Columbia Generation and Contract Expense	$480,093
5	Change in Net Transmission Expense (Expense - Revenues)	-$2,889,236
6	Change in Other Contract Expense and Revenues	$6,348,355
7	Change in Retail Loads (Power Cost Change less Retail Revenue Adjustment)	$606,348
8	Prior Period BPA Transmission Power and Ancillary Service Revenue	-$1,149,458
	Total Expense Below the Authorized Level	-$6,219,740

Notes:
1 Generation was higher in lower market price months and lower in higher market price months.
2 Includes change in gas generation market value and gas transport value.
3 Decrease in fuel expense more than offset reduced value of lower generation.
4 Cost increase exceeded value of increased generation.
5 Increased transmission revenue exceeded increased transmission expense.
6 Includes loss of PGE contract revenue and other cost and revenue variations.
7 WA allocation of cost associated with increased load less retail revenue adjustment credit.
8 Adjustment for a mis-calibrated meter dating back to 2011. Booked in December.

Table No. 2 below shows the change in generation and system loads in 2017 from the authorized level included in base rates:

Table No. 2:

2017 Generation and Load Differences from the Authorized Level	Change aMW	Change %
Change in Hydro Generation	11.8	2.1%
Change in Gas Fired Generation	-21.6	-5.8%
Change in Colstrip & Kettle Falls Generation	-9.8	-4.8%
Change in System Load	13.8	1.3%

IV. NEW LONG-TERM CONTRACTS ENTERED INTO IN 2016

Q. Please provide a brief description of new long-term contracts that the Company entered into in 2017.

A. The Company entered into five long-term power purchase contract in 2017. In March, the Company entered into a 121 month contract with Douglas County PUD for a share of the output of the Wells dam beginning September, 2018. In June, a contract was entered into with Chelan County PUD for a share of the output of the Rocky Reach and Rock Island dams for a period of January 2021 through December 2030. In November, the Company extended the contract with the City of Spokane's Waste-to-Energy plant that was set to end December 31, 2017, through December 30, 2022 (a term of 4 years and 364 days). The other agreements were two very small (less than 500 kW) hydro-electric PURPA power purchase. All of these contracts were extensions of existing power purchases and none of these new contract extensions were in place during the 2017 ERM review period.

Q. Are any long-term contracts subject to the limitation for inclusion in the ERM that was part of the settlement in Docket No. 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 long-term contracts that were in effect during the 2017 review period are subject to limitations on cost recovery.

V. 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. Availability factors for the Company's thermal plants during 2017 are shown in Table No. 3 below:

Table No. 3:

2017 Thermal Generation Plant Availability Factors	
Colstrip	86.4%
Coyote Springs 2	93.5%
Kettle Falls	81.2%
Lancaster	95.8%

VI. 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 Record: 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 2017, 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.

VII. 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 2017 result from the power supply revenues and expenses approved by the Commission in Docket No. UE-150204. 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 for generating plant fuel not burned is included as the net of natural gas sale revenue under Account 456 (revenue) and purchase expense under Account 557 (expense) to incorporate the total net change in thermal fuel expense.

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. 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. 4 below:

<u>Table No. 4:</u>

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 costs 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 2017 was $15.66/MWh in the remaining months.

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 2017 deferral report are included as Exhibit No.____ (WGJ-2). The December 2017 deferral report pages show all of the months, January through December of 2017.

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

A. Yes.