BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-15____

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 2014 calendar year review period. I provide an overview of the documentation the Company has provided in workpapers, which the Company had 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. Are other witnesses sponsoring testimony on behalf of Avista?

A. Yes. Company witness Mr. Ehrbar 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 2014's Monthly Power Cost Deferral Report provided to the Commission. These pages show the deferral calculations for the period January 2014 through December 2014. Page 1 of Exhibit No.___(WGJ-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 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 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 2013 calendar year was filed March 28, 2014 in Docket No. UE-140540. Order No. 01 was issued in that docket on July 10, 2014, and the Commission found that the power cost deferrals for 2013 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 2014?

A. During 2014 actual net power costs were lower than the authorized net power costs for the Washington jurisdiction by $9,526,640. 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), 25% of the next $6 million of difference above the $4 million deadband 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 in the rebate direction for 2014 amounted to $4,224,011, which consists of the following items:

1. Rebate of $4,144,980 related to 75% of the net power costs residing in the $4.0 million to $10.0 million sharing band ($5,526,640 * 75% = $4,144,980).
2. Rebate of $79,031 related to interest.

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

A. In summarizing 2014, decreased power supply expenses resulted primarily from higher hydro generation, favorable operating margins at the Company's natural gas-fired generation facilities, and lower fuel cost at the Kettle Falls wood-fired plant. For the year, hydro generation was 48.7 aMW above the authorized level.

Table No. 1 below shows the primary factors impacting power supply expense during 2014:

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

Factors Contributing to Decreased Power Supply Expense 2014 - Washington Allocation	
Change in Avista Owned Hydro Generation	($5,091,248)
Change in Gas Generation and Natural Gas and Power Prices	($5,999,327)
Change in Colstrip Generation and Fuel Expense	$781,866
Change in Kettle Falls Generation and Fuel Expense	($1,039,940)
Change in Mid Columbia Generation and Contract Expense	$1,005,105
Change in Net Transmission Expense (Expense - Revenues)	($117,317)
Change in Retail Loads (Power Cost Change less Retail Revenue Credit)	$934,221
Total Expense Above / (Below) the Authorized Level	($9,526,640)

Table No. 2 below shows the change in generation and system loads in 2014 from the authorized level included in base rates:

Table No. 2:

2014 Generation and Load Differences from the Authorized Level		
	Change aMW	Change %
Change in Hydro Generation	48.7	9.3%
Change in Gas Fired Generation	(49.4)	-13.7%
Change in Colstrip Generation	(6.1)	-3.5%
Change in Kettle Falls Generation	(8.6)	-22.4%
Change in System Load	21.6	2.1%

IV. NEW LONG-TERM CONTRACTS ENTERED INTO IN 2014

Q. Please provide a brief description of new long-term contracts that the Company entered into in 2014.

A. The Company entered into two long-term power purchase contracts and two long-term ancillary product sale contracts in 2014. The power purchase contracts included a purchase of a four percent share of the output of the Rocky Reach and Rock Island dams for 2015, and an approximately 37.5 month purchase agreement for the output from the City of Spokane's Waste-to-Energy plant. The sale contracts included two dynamic capacity (load and generation regulation services) sales to Pend Oreille County PUD and Sovereign Power (Kaiser Aluminum rolling mill).

Q. Are any long-term contracts subject to the limitation for inclusion in the ERM?

A. No. The 2006 Settlement Agreement in Docket No. UE-060181 regarding the continuation of the Company's Energy Recovery Mechanism (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 entered into in prior years that were in effect during the 2014 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.

A. The 2006 Settlement Agreement in Docket No. UE-060181 related to the ERM included a 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 2014 are shown in Table No. 3 below:

Table No. 3:

2014 Thermal Generation Plant Availability Factors	
Colstrip	82.3%
Coyote Springs 2	95.3%
Kettle Falls	82.1%

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 two confidential worksheets showing each natural gas and electric term (one month or longer) transaction during 2014, 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 2014 result from the power supply revenues and expenses approved by the Commission in Docket No. UE-120436. 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 change in revenue (from the authorized amount) related to the sale of renewable energy credits, net of the change in REC purchase expense, is tracked in a separate deferral that is not subject to the ERM's sharing bands.[1]

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 deadband 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:

[1] Starting in January 2015, per Section 5.2 of the Settlement Stipulation approved in Docket UE-140188, "the Parties agree that the costs associated with RECs purchased to comply with the Washington Energy Independence Act will be excluded from the REC tracking mechanism, and will be included in the determination of base power supply costs in a general rate case. Any differences in costs from that included in base power supply costs will be tracked through the ERM, and subject to the existing dead band and sharing bands".

Table No. 4:

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 calculation is based on the energy-classified portion of the average cost (fixed and variable) of production and transmission included in the Company's general rate case. The retail revenue credit in 2014 was $0.03215 per kilowatt-hour.

The monthly retail revenue adjustment in the ERM is computed by multiplying $0.03215 per kilowatt-hour times the difference between actual and authorized monthly retail kilowatt-hour sales. If actual kilowatt-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 kilowatt-hour sales are less than base, the retail revenue adjustment will result in a debit to the ERM deferral (increases power supply costs).[2]

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

[2] The Retail Revenue Credit rate changed to $32.15/MWh beginning January 1, 2013, which represents the energy-classified portion of the fixed and variable production and transmission revenue requirement, as established in the Company's cost of service study from its last general rate case.

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 2014 deferral report are included as Exhibit No.____ (WGJ-2). The December 2014 deferral report pages show all of the months, January through December of 2014.

Q. Please explain the SMUD adjustment included in the monthly ERM deferral calculation.

A. On lines 3 and 13 on page 1 of Exhibit No. _____ (WGJ-2), the revenue from SMUD REC sales is removed from both the actual and authorized SMUD sales revenues. This is done because the SMUD sale is a bundled energy and REC sale that is included in Account 447. The REC revenue is removed from Account 447 so that is can be separately tracked in the REC revenue deferral that is not subject to any sharing bands.

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

A. Yes.