BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-14____

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 ERM and provide a summary of the factors contributing to the power cost deferrals during the 2013 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 Ms. Pluth provides testimony concerning the monthly deferral entries and the deferral balance. Company witness Mr. Dempsey addresses the Unit 4 outage at the Colstrip Generating Facility ("Colstrip") that caused it to fall below a 70% availability factor for the 2013 ERM review period.

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 2013's Monthly Power Cost Deferral Report provided to the Commission. These pages show the deferral calculations for the period January 2013 through December 2013. 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. In its Order No. 5, issued February 3, 2004 in Docket No. UE-030751, the Commission approved and adopted a Settlement Stipulation (UE-030751 Stipulation) that resolved the issues related to the first review period.

Avista has made ERM annual review filings for each subsequent calendar year period. The annual ERM filing covering the 2012 calendar year was filed March 28, 2013 in Docket No. UE-130438. Order 01 was issued in that docket on July 11, 2013, and the Commission found that the power cost deferrals for 2012 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 2013?

A. During 2013 actual net power costs were higher than the authorized net power costs for the Washington jurisdiction by $5,037,302. 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 for 2013 amounted to $1,256,447, which consists of the following four items:

1. Surcharge of $518,651 related to 50% of the net power costs falling in the $4.0 million to $10.0 million sharing band ($1,037,302 * 50% = $518,651).
2. Rebate of $70,084 related to actual Colstrip fixed costs less than authorized costs related to Colstrip availability below 70%[1].
3. Surcharge of $808,681 due to an error related to the allocation of natural gas transport costs between the Company's power supply operations and the Company's natural gas distribution operations[2].
4. Rebate of $801 related to interest.

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

A. In summarizing 2013, increased power supply expenses resulted primarily from lower hydro generation at Company-owned plants and the 6-month outage at Colstrip Unit 4. For the year, hydro generation was 24.5 aMW below the authorized level at Avista-owned hydro plants and 27.1 aMW higher at the Mid Columbia contracted plants. The higher generation at Mid Columbia plants, however, comes with additional expense, which doesn't offset the lower generation at Avista owned plants. The loss of Colstrip Unit 4 beginning July

[1] Details regarding the adjustment for Colstrip fixed costs are provided in Ms. Pluth's testimony. Description of the conditions that caused Colstrip availability to fall below 70% is provided in Mr. Dempsey's testimony.

[2] Details regarding the adjustment due to an error related to the allocation of natural gas transport costs between the Company's power supply operations and the Company's natural gas distribution operations were provided in the December 2013 ERM Deferral Report filed with the Commission on January 16, 2014. This report has been provided in this filing as Exhibit No. ___(JMP-2).

1, 2013, through the end of the year resulted in over $5 million of increased expense for the Washington jurisdiction. In summary, without the loss of Colstrip Unit 4, actual and authorized power supply expense would have been close to equal, and there would have been no ERM deferral because any difference in expense would have been within the plus or minus $4 million deadband.

Table No. 1 below shows the primary factors impacting power supply expense during 2013:

Table No. 1:

Factors Contributing to Increased Power Supply Expense 2013 - Washington Allocation	
Change in Avista Owned Hydro Generation	$6,038,372
Change in Gas Generation and Natural Gas and Power Prices	-$3,938,375
Change in Colstrip Generation and Fuel Expense	$5,211,118
Change in Kettle Falls Generation and Fuel Expense	-$1,661,903
Change in Mid Columbia Generation and Contract Expense	-$2,375,631
Change in Net Transmission Expense (Expense - Revenues)	$281,806
Change in Retail Loads (Power Cost Change less Retail Revenue Credit)	$1,481,915
Total Expense Above the Authorized Level	$5,037,302

Table No. 2 below shows the change in generation and system loads in 2013 from the authorized level included in base rates:

Table No. 2:

2013 Generation and Load Differences from the Authorized Level	Change aMW	Change %
Change in Hydro Generation	2.6	0.5%
Change in Gas Fired Generation	41.3	11.5%
Change in Colstrip Generation	-33.1	-19.1%
Change in Kettle Falls Generation	-4.6	-12.0%
Change in System Load	21.4	2.1%

IV. NEW LONG-TERM CONTRACTS ENTERED INTO IN 2013

Q. Please provide a brief description of new long-term contracts that the Company entered into in 2013.

A. The Company entered into one new long-term contract in 2013. In April the Company entered into an approximate three-year contract for a small (411 kW) PURPA hydro plant in northeast Washington. This contract was included in the April 2013 deferral report filed with the Commission on May 15, 2013.

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

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 2013 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 regarding the continuation of the Company's Energy Recovery Mechanism (ERM) addressed 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 2013 are shown in Table No. 3 below:

Table No. 3:

2013 Thermal Generation Plant Availability Factors	
Colstrip	65.8%
Coyote Springs 2	91.8%
Kettle Falls	81.7%
Lancaster	95.4%

Mr. Dempsey discusses the outage at Colstrip that caused its availability factor to be below 70%. Ms. Pluth addresses the issue of Colstrip fixed costs in regards to the 2006 Settlement Agreement in Docket UE-060181.

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 2013, 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 2013 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.

The total change in net expense under the ERM is multiplied by the Washington allocation of 65.24%. 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:

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 2013 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).[3]

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 2013 deferral report are included as Exhibit No.____ (WGJ-2). The December 2013 deferral report pages show all of the months, January through December of 2013.

Q. Please explain the SMUD and Clearwater Paper adjustments 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.

[3] 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.

The credit on line 9, page 1 of Exhibit No. _____ (WGJ-2), labeled "Less Clearwater directly assigned to ID" removes the Clearwater Paper power purchase expense that is included in FERC Account 555 Purchased Power on page 1, line 1 of Exhibit No. _____ (WGJ-2). This credit, which began in July 2003, is a result of the Company entering into a power purchase and sale agreement with Clearwater Paper where the Company purchases up to 62 average megawatts on an annual basis from Clearwater Paper and sells the equivalent amount of power to Clearwater Paper. The expense of this purchase, as well as the revenue from the corresponding sale, is 100 percent allocated to the Idaho jurisdiction. The actual expense is included in Account 555, Purchase Power Expense on page 1, line 1 of the monthly deferral calculations and then removed on page 1 line 8 for the Washington ERM deferral calculation. As a result, no expense related to the purchase of Clearwater Paper generation is included in the Washington ERM deferrals. The Clearwater Paper purchase ended June 30, 2013.

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

A. Yes.