DAVID J. MEYER
VICE PRESIDENT AND CHIEF COUNSEL FOR
REGULATORY & GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851
DAVID.MEYER@AVISTACORP.COM

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-15-05
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	DIRECT TESTIMONY
AND NATURAL GAS CUSTOMERS IN THE	)	OF
STATE OF IDAHO	)	TARA L. KNOX
	)	

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

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

A. My name is Tara L. Knox and my business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Senior Regulatory Analyst in the State and Federal Regulation Department.

Q. Would you briefly describe your duties?

A. Yes. I am responsible for preparing the electric regulatory cost of service model for the Company, as well as providing support for the preparation of results of operations reports, among other things.

Q. What is your educational background and professional experience?

A. I am a graduate of Washington State University with a Bachelor of Arts degree in General Humanities in 1982, and a Master of Accounting degree in 1990. As an employee in the State and Federal Regulation Department at Avista since 1991, I have attended several ratemaking classes, including the EEI Electric Rates Advanced Course that specializes in cost allocation and cost of service issues. I am also a member of the Cost of Service Working Group and the Northwest Pricing and Regulatory Forum, which are discussion groups made up of technical professionals from regional utilities and utilities throughout the United States and Canada concerned with cost of service issues.

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

A. My testimony and exhibits will cover the Company's electric revenue normalization adjustment to the test year results of operations, the proposed Load Change Adjustment Rate to be used in the Power Cost Adjustment mechanism, and the electric cost of service study performed for this proceeding. A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit 13 composed of three schedules. Schedule 1 details the calculation of the proposed Load Change Adjustment Rate, Schedule 2 includes a narrative of the electric cost of service study process, and Schedule 3 presents the electric cost of service study summary results.

Q. Were these exhibit schedules prepared by you or under your direction?

A. Yes, they were.

II. ELECTRIC REVENUE NORMALIZATION

Q. Would you please describe the electric revenue normalization adjustment included in Company witness Ms. Andrews' pro forma results of operations?

A. Yes. The electric revenue normalization adjustment represents the difference between the Company's actual recorded retail revenues during the twelve months ended December 2014 test period, and base rate retail revenues on a normalized (pro forma) basis. The total revenue normalization adjustment increases Idaho net operating income by $4,056,000, as shown in adjustment column 2.07 on page 7 of Ms. Andrews Exhibit No. 12, Schedule 1.

The revenue normalization adjustment consists of four primary components: 1) re-pricing customer usage (adjusted for any known and measurable changes) to base tariff rates presently in effect, 2) adjusting customer load and revenue to a 12-month calendar basis (unbilled revenue adjustment), 3) weather normalizing customer usage and revenue, and 4) eliminating the provision for earnings sharing associated with the 2014 earnings test.

Q. Since these elements are combined into a single adjustment, would you please identify the impact of each component?

A. Yes. A breakdown of the four components of the revenue normalization is as follows:

1. The re-pricing of billed usage including the elimination of adder schedule revenue and related amortization expense (Schedule 59 Residential Exchange Credit, Schedule 91 Public Purpose Tariff Rider, Schedule 95 Optional Renewable Power and Schedule 97 BPA Settlement Adjustment)[1] results in a <u>reduction</u> to net income of $103,000..
2. The re-pricing of unbilled calendar usage and elimination of unbilled adder schedule revenue and expense results in a <u>reduction</u> to net income of $87,000.[2]
3. The weather adjustment <u>reduces</u> net income $393,000.
4. Finally, the elimination of the 2014 earnings sharing (customer share) results in an <u>increase</u> to net income of $4,639,000.

The combined impact of these four elements is an increase to net income $4,056,000.

Q. Please briefly summarize the electric weather normalization process.

---

[1] Municipal Franchise Fee and Power Cost Adjustment revenues and related expenses are eliminated in separate adjustments.

[2] The unbilled adjustment consists of removing December 2013 usage billed in January 2014 from the 2014 test year, adding December 2014 usage billed in January 2015 to the 2014 test year, and re-pricing the net usage at present base rates.

A. The Company's electric weather normalization adjustment calculates the change in kWh usage required to adjust actual loads during the 2014 test period to the amount expected if weather had been normal. This adjustment incorporates the effect of both heating and cooling on weather-sensitive customer groups. The weather adjustment is developed from a regression analysis of ten years of billed usage per customer and billing period heating and cooling degree-day data. The resulting seasonal weather sensitivity factors (use-per-customer-per-heating-degree day and use-per-customer-per-cooling-degree day) are applied to monthly test period customers and the difference between normal heating/cooling degree-days and monthly test period observed heating/cooling degree-days.

Q. Have the seasonal weather sensitivity factors been updated since the last rate case?

A. Yes. The factors used in the weather adjustment are based on regression analysis of monthly billed usage-per-customer from January 2004 through December 2013, which is the most recent completed analysis.

Q. What data did you use to determine "normal" heating and cooling degree days?

A. Normal heating and cooling degree days are based on a rolling 30-year average of heating and cooling degree-days reported for each month by the National Weather Service for the Spokane Airport weather station. Each year the normal values are adjusted to capture the most recent year with the oldest year dropping off, thereby reflecting the most recent information available at the end of each calendar year. The calculation includes the 30-year period from 1985 through 2014.

Q. Is this proposed weather adjustment methodology consistent with the methodology utilized in the Company's last general rate case in Idaho?

A. Yes. The process for determining the weather sensitivity factors and the monthly adjustment calculation is consistent with the methodology presented in Case No. AVU-E-12-08.

Q. What was the change in kWhs resulting from weather normalization for the twelve months ended December 2014 test year?

A. Weather was warmer than normal throughout 2014, except for February, which was colder than normal. The summer months of July and August were particularly hot. Since electric usage is impacted by both heating and cooling, weather normalization required an addition to usage for warm weather during the winter (partially offset by the February 2014 arctic outbreaks) and a reduction to usage for the hot summer. These offsetting impacts resulted in a relatively small annual weather adjustment even though the monthly variations were volatile.

Overall, the adjustment to normal required the addition of 340 heating degree-days during the heating season,[3] and the deduction of 199 cooling degree-days during the summer season.[4] The annual total adjustment to Idaho electric sales volumes was a reduction of 9,000,496 kWhs, which is approximately 0.3% of billed usage.

The electric system monthly weather adjustment volumes were provided to Company witness Mr. Johnson as an input to the Pro Forma Power Supply analysis.

III. PROPOSED LOAD CHANGE ADJUSTMENT RATE

Q. What is the Load Change Adjustment Rate?

A. The Load Change Adjustment Rate (LCAR) is part of the Power Cost Adjustment (PCA) mechanism that prices the change in power supply-related costs associated with the change in actual retail loads, from the retail loads

[3] The heating season includes the months of January through June and October through December.

[4] The summer season includes the months of June through September. June is included in both seasons because both heating load and cooling load fluctuations occur during the month.

that were used to set the PCA base costs. The LCAR determination process for all Idaho investor-owned utilities was established in IPUC Case No. GNR-E-10-03, Order No. 32206, which was approved on March, 15, 2011.

Q. How is the rate determined?

A. The proposed LCAR is determined by computing the proposed revenue requirement on the production and transmission costs contained within Ms. Andrews' Idaho electric pro forma total results of operations. The production/transmission revenue requirement amount is then divided by the Idaho normalized retail load used to set rates in order to arrive at the average production and transmission cost-per-kWh embedded in proposed rates. This amount is then multiplied by the proportion of production and transmission costs classified as energy-related in the cost of service study.

Q. Do you have an exhibit schedule that shows the calculation of the proposed LCAR?

A. Yes. Exhibit No. 13, Schedule 1 begins with the identification of the production and transmission revenue, expense and rate base amounts included in each of Ms. Andrews' actual, restating, and pro forma adjustments to results of operations. The "2016 Pro Forma Total" on line

35 at the bottom of page 1 shows the resulting production and transmission cost components.

Page 2 shows the revenue requirement calculation on the production and transmission cost components. The rate of return and debt cost percentages on Line 2 are inputs from the proposed cost of capital. The normalized retail load on Line 10 comes from the workpapers supporting the revenue normalization adjustment. Line 11 represents the average total production and transmission cost-per-kWh proposed to be embedded in Idaho customer retail rates. Lines 12 and 13 are values taken from the cost of service study report titled "Functional Cost Summary by Classification at Uniform Requested Return" representing total costs at unity. Line 12 shows the amount of production and transmission costs classified as energy related, while Line 13 shows the total production and transmission costs in the study.

The resulting 2016 LCAR on Line 14 is $0.02399 per kWh or $23.99 per MWh. The 2017 LCAR is $25.99 per MWh and the calculation is shown on Exhibit No. 13, pages 3 and 4 of Schedule 1. The calculation of the LCAR will be revised based on the final production and transmission costs, and rate of return, that are approved by the Commission in this case.

IV. ELECTRIC COST OF SERVICE

Q. Please briefly summarize your testimony related to the electric cost of service study.

A. I believe the Base Case cost of service study presented in this case is a fair representation of the costs to serve each customer group. The Base Case study shows Residential Service Schedule 1 provides less than the overall rate of return under present rates. All of the other service schedules provide more than the overall rate of return under present rates to varying degrees.

Q. What is an electric cost of service study and what is its purpose?

A. An electric cost of service study is an engineering-economic study, which separates the revenue, expenses, and rate base associated with providing electric service to designated groups of customers. The groups are made up of customers with similar load characteristics and facilities requirements. Costs are assigned or allocated to each group based on (among other things), test period load and facilities requirements, resulting in an evaluation of the cost of the service provided to each group. The rate of return by customer group indicates whether the revenue provided by the customers in each group recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers. Schedule 2 of Exhibit No. 13 explains the basic concepts involved in performing an electric cost of service study. It also details the specific methodology and assumptions utilized in the Company's Base Case cost of service study.

Q. What is the basis for the electric cost of service study provided in this case?

A. The electric cost of service study provided by the Company as Exhibit No. 13, Schedule 3 is based on the twelve months ended December 31, 2014 test year pro forma results of operations presented by Ms. Andrews in Exhibit No. 12, Schedule 1.

Q. Would you please explain the cost of service study presented in Exhibit No. 13, Schedule 3?

A. Yes. Exhibit No. 13, Schedule 3 is composed of a series of summaries of the cost of service study results. The summary on page 1 shows the results of the study by FERC account category. The rate of return by rate schedule and the ratio of each schedule's return to the overall return are shown on Lines 39 and 40. This summary was provided to Company witness Mr. Ehrbar for his consideration regarding rate spread and rate design. The results will be discussed in more detail later in my testimony.

Pages 2 and 3 are both summaries that show the revenue-to-cost relationship at current and proposed revenue. Costs by category are shown first at the existing schedule returns (revenue); next the costs are shown as if all schedules were providing equal recovery (cost). These comparisons show how far current and proposed rates are from rates that would be in alignment with the cost study. Page 2 shows the costs segregated into production, transmission, distribution, and common functional categories. Line 44 on page 2 shows the target change in revenue which would produce unity in this cost study. Page 3 segregates the costs into demand, energy, and customer classifications. Page 4 is a summary identifying specific customer-related costs embedded in the study.

The Excel model used to calculate the cost of service and supporting schedules has been included in its entirety both electronically and in hard copy in the workpapers accompanying this case.

Q. Given that the specific details of this methodology are described in the narrative in Exhibit No. 13, Schedule 2, would you please give a brief overview of

the key elements and the history associated with those elements?

A. Yes. Production costs are classified to energy and demand in this case based on the system load factor. The Company proposed this approach in Case No. AVU-E-11-01. While the Company chose to use the traditional replacement-cost-based peak credit methodology in the last Idaho case (Case No. AVU-E-12-08), we believe that the system load factor method is preferable, as I discuss later in my testimony.

Transmission costs are classified as 100% demand and allocated by the average of the 12 monthly coincident peaks. This methodology is the same treatment as the last Idaho case (Case No. AVU-E-12-08) and reflects the methodology accepted in the Settlement in Case No. AVU-E-10-01.

Distribution costs are classified and allocated by the basic customer theory[5] accepted by the Idaho Commission in Case No. WWP-E-98-11. Additional direct assignment of demand-related distribution plant has been incorporated to reflect improvements accepted by the Commission in Case No. AVU-E-04-01.

[5] Basic customer cost theory classifies only meters, service lines from the distribution system to the customer's premise, and street lights as customer-related plant; all other distribution facilities are considered demand-related.

Administrative and general costs are first directly assigned to production, transmission, distribution, or customer relations functions. The remaining administrative and general costs are categorized as common costs and have been assigned to customer classes by the four-factor allocator accepted by the Idaho Commission in Case No. AVU-E-04-01.

Q. Does the Company's electric Base Case cost of service study follow the methodology filed in the Company's last electric general rate case in Idaho?

A. Yes, with one exception. The peak credit methodology used for classification of production costs into energy-related and demand-related categories is different from the traditional peak credit determination presented in the last Idaho general rate case.

Q. What is the Company proposing in this case with regard to the peak credit methodology?

A. In this case the Company is proposing to use the system load factor to determine the proportion of the production function that is demand-related.[6] This peak credit ratio is then applied uniformly to all production costs. This is the same method the Company proposed in

[6] One minus the load factor equals the demand percentage or peak credit ratio.

Case No. AVU-E-11-01 that was derived from ideas developed through cost of service workshops held at the Idaho Commission in February 2011 and September 2012.

Q. What do you believe are the benefits of using the system load factor to determine the peak credit ratio?

A. There are several benefits to the system load factor approach for identifying the demand-related proportion of production costs: 1) It is simple and straightforward to calculate; 2) it is directly related to the system and test year under evaluation; and 3) the relationship should remain relatively stable from year to year.

Q. How was the peak credit methodology determined and applied in past studies?

A. In the Company's cost of service studies prior to 2010 and the 2012 case (AVU-E-12-08), Avista's electric system resource costs were classified to energy and demand using a comparison of the replacement cost per kW of the Company's peaking units, to the replacement cost per kW of the Company's thermal and hydro plants (separately). This analysis created separate peak credit ratios applied to thermal plant and hydro plant. Fuel and load dispatching expenses were classified entirely to energy, and peaking plant related costs were classified entirely to demand.

Q. What is the net effect of the proposed change in the peak credit method?

A. The net effect of this change is to increase the overall production costs that are classified as demand-related. Using the prior method, approximately 31.28% of total production costs would be classified as demand-related. Under the proposed method, 37.93% of total production costs are classified as demand-related. In this circumstance, costs are shifted toward the low load factor residential and small commercial class, and away from all the other classes. However, the impact on the cost study results is relatively minor. The shift in costs at unity were less than 1% of present revenue for all schedules except Schedule 25P where costs at unity were reduced by 1.5%.

Q. Did the Company use recent load research for demand-related cost allocations in the electric cost of service study in this case?

A. Yes. The Company contracted with DNV-GL[7] to develop hourly load estimates by rate class for cost of service demand allocation purposes. The study was completed in December 2014 with the final report provided

[7] The DNV-GL Group (Det Norske Veritas, Germanischer Lloyd) is an industry leader in load research for the energy sector, providing comprehensive services from initial study planning to analysis and final reporting.

in January 2015. The new load research study, included with the Company's workpapers in this filing, utilized sample metering in place from the last load study (discussed in Case No. AVU-E-10-01, the Company's 2010 general rate case) augmented by additional sample sites added during the intervening years. The study is based on data collected over the period July 1, 2013 through June 30, 2014.

Q. Did the 2014 load study show any major changes in usage across the customer classes?

A. No, other than the change from a purchase and sale contract to self-generation for Schedule 25P, there were no major changes. The study did capture the impact of schedule shifting from Schedule 21 to Schedule 11 that occurred several years ago and the residential class shows a slightly higher contribution to the peaks than in the 2009 study. In general the results were consistent with prior study results.

Q. What are the results of the Company's electric cost of service study presented in this case?

A. Illustration No. 1 below shows the rate of return and the relationship of the customer class return to the overall return (relative return ratio) at <u>present rates</u> for each rate schedule:

Illustration No. 1:

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 1	4.94%	0.76
General Service Schedule 11/12	8.78%	1.34
Large General Service Schedule 21/22	7.57%	1.16
Extra Large General Service Schedule 25	6.73%	1.03
Extra Large General Service Clearwater Paper Schedule 25P	9.20%	1.41
Pumping Service Schedule 31/32	7.10%	1.09
Lighting Service Schedules 41 - 49	6.61%	1.01
Total Idaho Electric System	6.53%	1.00

As can be observed from the above table, Residential service Schedule 1 shows under-recovery of the costs to serve them. The Extra Large General service Schedule 25, the Pumping service schedule (31/32) and the Lighting service schedules (41-49) are slightly over, but very near unity. The General, Large General and Extra Large General-Clearwater Paper service schedules (11/12, 21/22, and 25P) show over-recovery of the costs to serve them. The summary results of this study were provided to Mr. Ehrbar for consideration in the development of proposed rates.

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

A. Yes.