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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-11-01 CASE NO. AVU-G-11-01 DIRECT TESTIMONY OF TARA L. KNOX

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

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 regulatory cost of service models for the Company, as well as providing support for the preparation of results of operations reports.

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 have also been 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 and natural gas cost of service studies performed for this proceeding. Additionally, I am sponsoring the electric and natural gas revenue normalization adjustments to the test year results of operations and the proposed Load Change Adjustment Rate (LCAR) to be used in the Power Cost Adjustment (PCA). A table of contents for my testimony is as follows:

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Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit 12 composed of six schedules as follows. Schedule 1, which illustrates the proposed Load Change Adjustment Rate calculation; Schedule 2, the electric cost of service study process description; Schedule 3, the electric cost of service study summary results; Schedule 4, the cost of service workshop presentation; Schedule 5, the natural gas cost of service study process description; and Schedule 6, the natural gas cost of service study summary results.

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

A. Yes, they were.

<u>II. REVENUE NORMALIZATION</u>

<u>Electric Revenue Normalization</u>

Q. Would you please describe the electric revenue 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 2010 test period, and retail revenues on a normalized (pro forma) basis. The total revenue normalization adjustment increases Idaho net operating income by $11,504,000, as shown in column (z) on page 8 of Ms. Andrews Exhibit No. 10, Schedule 1. The revenue normalization adjustment consists of three primary components: 1) re-pricing customer usage (adjusted for any known and measurable changes) at base tariff rates presently in effect, 2) adjusting customer loads and revenue to a 12-month calendar basis (unbilled revenue adjustment), and 3) weather normalizing customer usage and revenue[1].

Q. Since these three elements are combined into a single adjustment, would you please identify the impact

[1] Documentation related to this adjustment is detailed in the Knox workpapers accompanying this case.

(before taxes and revenue related expenses) of each component?

A. Yes. The re-pricing of billed usage comprises the majority of the change in test year revenue. The combined impact of the rate increase effective October 1, 2010[2], and the elimination of revenue and amortization expense from adder schedules (Schedule 59 Residential Exchange, Schedule 91 Public Purpose Tariff Rider, and Schedule 95 Optional Renewable Power[3]), is an <u>increase</u> in net revenue of $16,612,000. Re-pricing of unbilled calendar usage and elimination of unbilled adder schedule revenue and expense results in a net revenue <u>reduction</u> of $1,229,000[4]. Finally, the weather normalization adjustment <u>increases</u> revenue by $2,649,000. The combined impact of these elements is an increase of $18,032,000 which, after revenue-related expenses and income tax, results in the increase to net operating income of $11,504,000.

Q. Would you please briefly discuss electric weather normalization?

A. Yes. The Company's electric weather normalization adjustment calculates the change in kWh usage required to adjust actual loads during the twelve months ended December 2010 test period to the amount expected if weather had been normal. This adjustment incorporates the

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[2] IPUC Case No. AVU-E-10-1.
[3] Municipal Franchise Fee and Power Cost Adjustment revenues are eliminated in separate adjustments.
[4] The unbilled adjustment consists of removing December 2009 usage billed in January 2010 from the 2010 test year, adding December 2010 usage billed in January 2011 to the 2010 test year, and re-pricing the net adjustment to usage at October 1, 2010 rates.

effect of both heating and cooling on weather-sensitive customer groups. The weather adjustment is developed from 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 2000 through December 2009 which is the most recent completed analysis. Autoregressive terms were included in the regressions in order to correct for autocorrelation in the data.

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.

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 generally consistent with the methodology presented in Case No. AVU-E-10-1.[5]

Q. What was the impact of electric weather normalization on the twelve months ended December 2010 test year?

A. Weather was warmer than normal during the winter, and cooler than normal during the spring and summer of 2010. The adjustment to normal required the addition of 334 heating degree-days during the heating season[6] and 59 cooling degree-days. The total adjustment to Idaho sales volumes was an addition of 31,023,829 kWhs which is approximately 0.9% of billed usage.

Natural Gas Revenue Normalization

[5] One difference may be observed between the cases. Due to the addition of autoregressive terms in the regression analysis, it was possible to include the desired ten years of data in this case, whereas in the prior case only five years of data had been used for Idaho electric customer groups in order to pass the Durbin Watson test for autocorrelation without autoregressive terms.

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

Q. Would you please describe the natural gas revenue adjustment included in Ms. Andrews pro forma results of operations?

A. Yes. The natural gas revenue normalization adjustment is similar to the electric adjustment and represents the difference between the Company's actual recorded retail revenues during the twelve months ended December 2010 test period and retail revenues on a normalized (pro forma) basis. The adjustment includes the re-pricing of pro forma sales and transportation volumes at present rates using pro forma sales volumes that have been adjusted for unbilled sales, abnormal weather, and any material customer load or schedule changes. The rates used exclude: 1) Temporary Gas Rate Adjustment Schedule 155, which reflects the approved amortization rate for prior deferred gas costs approved in the Company's last PGA filing, 2) Public Purposes Rider Adjustment Schedule 191, and 3) Deferred State Income Tax Adjustment Schedule 199[7].

Q. Does the Revenue Normalization Adjustment contain a component reflecting normalized gas costs?

A. Yes. Purchase gas costs are normalized using the gas costs approved by the Commission in Case No. AVU-G-10-3, the Company's 2010 PGA filing, as set forth under Schedule 150. These gas costs, effective November 1, 2010, are applied to the pro forma retail sales volumes so that there is a matching of revenues and gas costs.

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[7] Documentation related to this adjustment is detailed in the Knox workpapers accompanying this case.

Q. Have you determined the impact of each of the components of this adjustment?

A. Yes. The re-pricing of billed revenue and gas costs increased margin[8] by $1,263,000. Re-pricing unbilled revenue and gas costs decreased margin by $463,000, and the weather adjustment at present rates increased margin by $1,088,000.

The total net amount of the natural gas revenue normalization adjustment, which includes the related purchase gas cost normalization, is an increase to net operating income of $1,189,000, as shown in column (i), page 8 of Ms. Andrews Exhibit No. 10, Schedule 2.

Q. Would you please briefly discuss natural gas weather normalization?

A. Yes. The natural gas weather normalization adjustment is developed from a regression analysis of ten years of billed usage per customer and billing period heating degree-day data. The resulting seasonal weather sensitivity factors (use-per-customer-per-heating-degree day) are applied to monthly test period customers and the difference between normal heating degree-days and monthly test period observed heating degree-days. This calculation produces the change in therm usage required to adjust existing loads to the amount expected if weather had been normal.

[8] The term "margin" in this context consists of revenues less gas costs and adder schedule amortization expenses but does not include the effect of revenue related expenses or income taxes.

Q. In your discussion of electric weather normalization you indicated that the adjustment utilized sensitivity factors from the ten year period January 2000 through December 2009. Is this true for natural gas as well?

A. Yes, the natural gas weather adjustment utilized updated weather sensitivity factors.

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

A. Normal heating degree-days are based on a rolling 30-year average of heating 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.

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 are consistent with the methodology presented in Case No. AVU-G-10-01.

Q. What was the impact of natural gas weather normalization on the twelve months ended December 2010 test year?

A. Weather was warmer than normal during the 2010 winter months, somewhat offset by a cooler than normal spring and fall. The adjustment to normal required the addition of 334 heating degree-days from January through June and October through December.[9] The adjustment to sales volumes was an addition of 3,225,558 therms which is approximately 2.8 percent of billed usage.

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 PCA mechanism that prices the change in actual retail loads from the retail loads that were used to set the PCA base costs.

Q. In prior cases, wasn't this called the "Retail Revenue Credit Rate"?

A. Yes. September of last year, the Idaho Commission opened Case No. GNR-E-10-03 titled IN THE MATTER OF THE COMMISSION'S INQUIRY INTO LOAD GROWTH ADJUSTMENTS THAT ARE PART OF POWER COST ADJUSTMENT MECHANISMS. This proceeding resulted in a modified calculation methodology of the "Load Change Adjustment Rate" (LCAR) to be used beginning April 1, 2011 by all of the investor-owned electric utilities in their various power cost adjustment mechanisms.

[9] Heating degree days that occur during July through September do not impact the natural gas weather normalization adjustment as the seasonal sensitivity factor is zero for summer months.

Q. How is the new LCAR different from the former Retail Revenue Credit Rate?

A. The new LCAR includes only the proportion of production and transmission costs that are classified as energy-related in the Company's cost of service study to determine the rate. The former retail revenue credit rate used all production and transmission costs to determine the rate.

Q. How is the rate determined?

A. The proposed LCAR in this case 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. 12, 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 "Pro Forma Total Production and

Transmission Costs" 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 and energy efficiency load adjustments. 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 supporting report titled <u>Functional Cost Summary by Classification at Uniform Requested Return</u> 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 load change adjustment rate on Line 14 is $0.02633 per kWh or $26.33 per MWh. The calculation of the load change adjustment rate 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, Extra Large General Service Schedule 25, Pumping Service Schedule 31 and the Street and Area Lighting Schedules provide moderately less than the overall rate of return under present rates. General Service Schedule 11, Large General Service Schedule 21 and Extra Large General Service to Clearwater Paper Schedule 25P provide more than the overall rate of return under present rates.

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. Exhibit No. 12, Schedule 2 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. 12, Schedule 3 is based on the twelve months ended December 2010 test year pro forma results of operations presented by Ms. Andrews in Exhibit No. 10, Schedule 1.

Q. Would you please explain the cost of service study presented in Exhibit No. 12, Schedule 3?

A. Yes. Exhibit No. 12, 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 work on 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. 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. In most respects, yes. The Base Case cost of service study was prepared using the methodology applied to the study presented in Case No. AVU-E-04-01 through Case No. AVU-E-09-01 <u>except</u> that the <u>peak credit</u> classification of production and transmission costs has been revised. While a revision to the peak credit classification of production and transmission costs was also proposed in Case No. AVU-E-10-01, only the classification of transmission costs as 100% demand-related was accepted as part of the settlement in that case. Therefore the "Prior Methodology" refers to the study methodology last presented in Case No.

AVU-E-09-01 modified only to reflect the transmission costs classification change.

Q. Given that the specific details of this methodology are described in Exhibit No. 12, 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. This is a new proposal due to the discussions at the cost of service workshop arising from the Settlement in Case No. AVU-E-10-01. Transmission costs are classified as 100% demand and allocated by weighted 12 month coincident peaks. While the transmission demand classification was accepted in the Settlement in Case No. AVU-E-10-01, the weighted 12 month coincident peak allocation is a new proposal discussed at the cost of service workshop required by the Settlement Stipulation in Case No. AVU-E-10-01.

Distribution costs are classified and allocated by the basic customer theory[10] 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.

Administrative and general costs are first directly assigned to production, transmission, distribution, or customer relations functions. The remaining administrative

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[10] Basic customer theory classifies only meters, services and street lights as customer-related plant; all other distribution facilities are considered demand-related

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. You mentioned a cost of service workshop arising from the settlement in Case No. AVU-E-10-01. Please explain.

A. In Order No. 32070 from Case No. AVU-E-10-01 and AVU-G-10-01, the Commission approved an all-party Settlement Stipulation. In Section 11 of the Settlement Stipulation, beginning on page 5 it states:

> The Parties have otherwise agreed to exchange information and convene a public workshop, prior to the Company's next general rate case, with respect to the possible use of a revised peak credit method for classifying production costs, as well as consideration of the use of a 12 CP (whether "weighted" or not) versus a 7 CP or other method for allocating transmission costs.

The workshop was convened on February 8, 2011 at the Idaho Public Utilities Commission, and was attended by the key stakeholders regarding cost of service issues.[11] The Company's presentation and handouts from the workshop have been included as Schedule 4 of Exhibit No. 12.

Q. Regarding production cost classification, the workshop presentation emphasizes the benefits of the IRP based methodology Avista proposed in Case No. AVU-E-10-01. Why are you moving away from that approach in this case?

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[11] Parties attending the workshop included Avista, IPUC Staff, Idaho Forest Group, Clearwater Paper, Idaho Conservation League, and Idaho Power Company.

A. A number of issues were raised in the workshop which led to a re-evaluation of that approach, as well as the applicability of an entirely future-based relationship in an embedded cost study. A system load factor alternative was raised during the workshop, and the Company determined that this approach to peak credit better met our requirements to improve the production and transmission cost classification process.

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.[12] This single peak credit ratio is then applied uniformly to all production costs.

Q. How was the prior peak credit methodology determined and applied to production costs?

A. In the Company's prior cost of service studies, 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 costs. Fuel and system control expenses were classified

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

entirely to energy, and peaking plant related costs were classified entirely to demand.

Q. What 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 electric system and test year under evaluation, and 3) the relationship should remain relatively stable from year to year (i.e., not vary with changes in natural gas costs).

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

A. The net effect of this change is to <u>slightly</u> increase the overall level of production costs that are classified as demand-related. Using the prior method, approximately 31.97% of total production costs were classified as demand-related. Under the proposed method, 36.41% of total production costs are classified as demand-related. This change shifts costs away from high load factor customer groups (Schedules 21, 25, and 25P) as well as customer groups which have a limited contribution to system peak usage (pumping and street lighting).

Q. You also mentioned a change to the allocation of transmission costs, what are you proposing in this case?

A. All transmission costs are allocated to customer classes in this case by their weighted 12-month coincident peak demand. The peak demand by schedule at the time of each monthly system peak in the test year is weighted by the amount that the electric system peak demand in that month exceeded the annual average system demand as a proportion of the twelve month total excess system demand.

The weighting process is illustrated in Exhibit No. 12, Schedule 4, page 15. In this example, January system peak demand of 1,779 MW exceeded annual average demand (energy) of 1,134 aMW by 645 MW. 645 MW was 12.4% of the sum of each month's excess demand of 5,188 MW. Therefore, 12.4% of January coincident peak demand by schedule was included in the weighted 12CP allocation factor.

Q. In Case No. AVU-E-10-01 you had proposed a 7CP allocation factor for transmission costs, while in prior cases demand-related transmission costs were allocated by an unweighted 12 CP allocation factor. Why are you proposing the weighted 12 CP in this case?

A. The 7CP allocation was proposed in the last case to acknowledge that lower customer demands in the off-peak fall and spring seasons do not impose the same capacity utilization of the transmission facilities as the high demand winter and summer seasons. The weighted 12 CP allocation (developed for the workshop) is a more robust method to capture the seasonal impacts on transmission capacity utilization. As such, the Company considers this allocation to be a better representation of the demands on the transmission system than either the straight average of all monthly demands which does not recognize any seasonal differences, or the average of the seven highest months which ignores shoulder month demand entirely.

Q What is the impact on the study of moving from the 12CP (per the settlement in AVU-E-10-01) to the weighted 12CP in this case?

A. The net effect of this change is that more costs are assigned to both residential and street and area light customers, while all other customer classes benefit to varying degrees. Street and area lights only contribute to the system peak if that peak occurs after dark. This generally only happens during the winter months which naturally have more weight (i.e., more excess demand) than the spring and summer months. Similarly, due to heating loads, residential customers have their highest relative demand during winter months which have more weight than other times of the year.

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

A. The following table shows the rate of return and the relationship of the customer class return to the overall return (relative return ratio) at present rates for each rate schedule:

Illustration 1

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 1	6.27%	0.83
General Service Schedule 11/12	10.48%	1.38