RECEIVED

2019 JUN 10 AM 10: 10

IDAHO PUBLIC
UTILITIES COMMISSION

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 OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO	)))))))	CASE NO. AVU-E-19-04 DIRECT TESTIMONY OF TARA L. KNOX

FOR AVISTA CORPORATION

(ELECTRIC)

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 Manager of Regulatory Accounting Initiatives in the Regulatory Affairs Department.

Q. Would you briefly describe your duties?

A. Yes. I am responsible for preparing the electric cost of service studies 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 Regulatory Affairs 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 and Fixed Cost Adjustment mechanisms, and the electric cost of service studies 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 No. 11 composed of five 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, Schedule 3 presents the base case electric cost of service study summary results, Schedule 4 is the electric cost of service workshop presentation, and Schedule 5 presents key results from the alternative cost of service studies.

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 12-months ended December 2018 test period, and base rate retail revenues on a normalized (pro forma) basis. The total revenue normalization adjustment increases Idaho net operating income by $1,512,000, as shown in adjustment column 2.07 on page 6 of Ms. Andrews' Exhibit No. 4, 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 both the deferred revenue associated with the 2018 Fixed Cost Adjustment (FCA) mechanism and the 2017 Tax Reform Provision for Rate Refund included in 2018 results.

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 effects of the January 1, 2019 base rate increase including Permanent Tax Reform rate adjustment Schedule 72 (AVU-E-17-01, Compliance Filing 2), as well as the elimination of adder schedule revenue and related amortization expense (Schedule 59 Residential Exchange Credit, Schedule 75 Fixed Cost Adjustment, Schedule 91 Public Purpose Tariff Rider, Schedule 95 Optional Renewable Power and Schedule 97 Rebate of Electric Earnings Test Deferral)[1] results in a <u>decrease</u> to net income of $1,714,000.[2]

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

[2] This analysis reclassifies Schedule 25 and 25P unbilled transition from no lag (0% unbilled) to one-month lag (100% unbilled) to represent the unbilled amounts reflected in pro forma billed usage.

2. The re-pricing of unbilled calendar usage and elimination of unbilled adder schedule revenue and expense results in an increase to net income of $77,000.[3]
3. The weather adjustment increases net income $1,245,000.
4. The elimination of the 2018 FCA deferred revenue and tax reform provision for rate refund increases net income by $1,904,000.

The combined impact of these four elements is an increase to net income of $1,512,000.

Q. Earlier you stated that customer usage is "adjusted for any known and measurable changes". What material usage adjustments were made to the 2018 test year?

A. One large customer moved from Schedule 25 to Schedule 21 after the test year. The schedule shifting impact was reflected in the re-pricing of billed usage.

Q. Please briefly summarize the electric weather normalization process.

A. The Company's electric weather normalization adjustment calculates the change in kWh usage required to adjust actual loads during the 2018 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.

[3] The unbilled adjustment consists of removing December 2017 usage billed in January 2018 from the 2018 test year, adding December 2018 usage billed in January 2019 to the 2018 test year, and re-pricing the net usage at present base rates.

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 use-per-customer from January 2007 through December 2016, 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 1989 through 2018.

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-17-01.

Q. What was the change in kWhs resulting from weather normalization for the 12-months ended December 2018 test year?

A. Weather was warmer than normal most of the 2018 test year. Since electric usage is impacted by both heating and cooling, weather normalization required an addition to usage for warm weather during the winter months that was offset by a reduction to usage for some colder than normal spring months and hot summer months. Overall, the adjustment to normal required the addition of 447 heating degree-days during the heating season,[4] and the deduction of 78 cooling degree-days during the summer season.[5] The annual total adjustment to Idaho electric sales volumes was an addition of 17,386,949 kWhs, which is approximately 0.6% of billed usage. The electric system monthly weather adjustment volumes were provided to Company witness Mr. Kalich as an input to the Pro Forma Power Supply adjustment.

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 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. The LCAR is also a key component in the Company's electric Fixed Cost Adjustment (FCA) mechanism.[6]

Q. How was the LCAR determined?

A. The proposed LCAR was determined by first computing the proposed revenue requirement on the total production and transmission costs contained within Ms.

---

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

[5] 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. May was also adjusted for cooling in 2018 as the month was extraordinarily warm.

[6] As required in the Company's FCA, the LCAR from the PCA (grossed up for revenue-related expenses) multiplied by kWh sales is deducted from base rate revenues in the FCA to ensure that no overlap occurs between the PCA and the FCA.

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. The LCAR, therefore, represents the energy-related portion of Avista's production and transmission costs, on a per-kWh basis.

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

A. Yes. Exhibit No. 11, 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 "2020 Pro Forma Total" on Line 32 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" which represents 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 2020 LCAR on Page 2, Line 14 is $0.02341 per kWh or $23.41 per MWh. The calculation of the LCAR for the rate year 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 electric 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 General Service Schedules 11/12, Large General Service Schedules 21/22 and Street and Area Lighting Schedules 41-49 provide more than the overall rate of return under present rates. All of the other service schedules provide less 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. 11 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.

<u>BASE CASE ELECTRIC COST OF SERVICE STUDY</u>

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

A. The electric cost of service study provided by the Company as Exhibit No. 11, Schedule 3 is based on the 2018 Pro Forma Study presented by Ms. Andrews in Exhibit No. 4, Schedule 1.

Q. Would you please explain the cost of service study presented in Exhibit No. 11, Schedule 3?

A. Yes. Exhibit No. 11, 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. Miller 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. 11, 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 has proposed this approach in prior general rate cases (Case Nos. AVU-E-11-01, AVU-E-15-05, AVU-E-16-03 and AVU-E-17-01).

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 four Idaho cases (Case Nos. AVU-E-12-08, AVU-E-15-05, AVU-E-16-03 and AVU-E-17-01) 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 accepted by the Idaho Commission in Case No. WWP-E-98-11.[7] 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 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.

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

A. Table No. 1 below summarizes the Base Case cost of service study results:

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

Table No. 1:

Customer Class	Rate of Return	Return Ratio	Revenue to Cost Ratio	Cost Less Revenue
				$000s
Residential Service Schedule 1	5.81%	0.82	0.93	$8,376
General Service Schedules 11/12	10.77%	1.52	1.12	($4,180)
Large General Service Schedules 21/22	7.70%	1.09	1.00	($179)
Extra Large General Service Schedule 25	6.22%	0.88	0.95	$922
Extra Large General Service Clearwater Paper Schedule 25P	6.68%	0.94	0.97	$713
Pumping Service Schedules 31/32	6.82%	0.96	0.97	$201
Lighting Service Schedules 41 - 49	10.88%	1.54	1.20	($598)
Total Idaho Electric System	7.08%	1.00	0.98	$5,255

The first two columns show 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. The next column presents the ratio of revenue provided by present rates divided by the total cost of service at the requested overall return (revenue to cost ratio), followed by the dollar value of the difference between total cost and present revenue for each customer class.[8]

As can be observed from the above table, Residential Service Schedule 1, both Extra Large General Service Schedules 25 and 25P, and Pumping Service Schedules (31/32) show under-recovery of the costs to serve them. The General, Large General, and Lighting Service Schedules (11/12, 21/22, and 41-49) show over-recovery of the costs to serve them. The summary results of this study were provided to Mr. Miller for consideration in the development of proposed rates.

[8] In my cost of service exhibit the Cost less Revenue value is called "Target Revenue Increase" and may be found on Exhibit 11, Schedule 3, page 2, at line 44.

ALTERNATIVE COST OF SERVICE STUDIES

Q. In the Company's last general rate case, the Stipulation and Settlement approved by the Commission included agreement to hold a workshop to "meet and confer regarding the Company's electric cost of service study". Has this workshop taken place?

A. Yes, the workshop was held on March 27, 2019 at the Commission hearing room in Boise. In addition to Avista, representatives of Commission Staff, Idaho Forest Group (IFG), Clearwater Paper, and Idaho Conservation League (ICL) attended the workshop (Jointly "the Parties").

Q. What was discussed in this workshop?

A. Prior to the workshop the Company reached out to the Parties for input regarding what they would like to discuss at the workshop. Based on their input, the Company created the presentation attached as Exhibit 11, Schedule 4. Workshop discussion topics included methods to measure movement toward unity with cost of service and each of the classification and allocation scenarios presented in this exhibit.

Q. How does the Company usually measure movement toward unity with cost of service?

A. Avista uses the relationship of each customer group's earned return to the overall Idaho electric earned return, called the return ratio, as the measure of relative cost recovery provided by present and proposed rates. At the workshop Commission Staff expressed interest in considering a revenue-to-cost measurement of alignment with the cost study in addition to the return ratio.

Q. What is revenue-to-cost and what does it add to interpretation of cost study results?

A. Revenue-to-cost is a stand-alone measure of how each group's revenue compares to total cost of service for the group (as indicated by the cost study). It can be shown as a ratio of revenue divided by cost or the difference of cost less revenue. A revenue-to-cost ratio less than 1.00 indicates that the customer group is not covering the costs to serve them, whereas a ratio greater than 1.00 indicates that the customer group is paying more than the cost to serve them (providing a subsidy to other groups). When shown as the difference of cost less revenue, the value represents the revenue change necessary to equal the cost of service indicated by the cost study.

Table No. 1, above (page 12) included both "revenue-to-cost" ratios and "cost less revenue" values in addition to the rate of return and return ratios produced by the Company's Base Case cost of service study presented as Exhibit 11, Schedule 3. The implications of both measures are essentially the same, but generally the return ratio is more sensitive to moderate revenue change proposals.

Q. Moving on to cost of service methodology, in the Settlement Stipulation in the 2017 Case the Company agreed to provide, at a minimum, three cost of service studies in this rate case.[9] Did the workshop discussion arrive at methodologies the parties wanted to see?

A. There were many different thoughts shared at the workshop. The workshop concluded with agreement that the parties would confer among themselves and provide any other methodology suggestions to Avista. On April 15, 2019, IFG submitted

[9] AVU-E-17-01 Settlement Stipulation Provision 17 approved by IPUC Order No. 33953.

written comments identifying recommendations for the electric cost of service studies in this case. Based on the conversations held at the workshop and IFG's written comments, Avista developed three methodological alternatives.

Q. Would you please describe your first alternative methodology?

A. For all of the scenarios, I started with the Company Base Case (which represents the methodology presented in all recent prior cases) and made specific changes. The first scenario (Scenario 1) incorporated the classification of Distribution Land and Land Rights (FERC Plant Account 360) as related to other distribution plant in FERC Plant Accounts 361 through 367. The rationale behind this modification is that the land or land rights are not directly related to customer demand, but rather are necessary support for the substations and distribution lines that provide service to customers.

Q. What were the results of this scenario?

A. Please see Page 1 of Exhibit 11, Schedule 5 which shows the key results of alternative Scenario 1, as well as a comparison to the Base Case results. Lines 17 and 18 show the impact of this change in methodology on the return ratio and total costs produced by the study. Scenario 1 is not a material change from the Company Base Case.

Q. Would you please describe your second alternative methodology?

A. The second scenario (Scenario 2) modified the coincident peak allocation factor which is used on all demand-related production and transmission costs to reflect the average of the seven highest monthly peaks during the test period. For the 2018 test period, the seven highest peak months were August, July, February, January, December, March and November (ordered from highest to lowest peak values). The purpose of this scenario is to emphasize the winter and summer peaks in the assignment of demand-related costs.

Q. What was the impact of this methodology change?

A. Please see Page 2 of Exhibit 11, Schedule 5 which shows key results of alternative Scenario 2, as well as a comparison to the Base Case results. This change increased costs considerably for the Residential customer group, slightly for Street and Area Light group and reduced costs for all other rate groups especially Large General Service as shown on line 18. On a relative basis, the greatest impact was to Pumping Service where the return ratio improved from 0.96 to 1.22 as a result of removing spring and fall contributions to the coincident peak cost assignment.

Q. Would you please describe your third alternative methodology?

A. The third scenario (Scenario 3) also involved modification of the coincident peak allocation factor which is used on all demand-related production and transmission costs. This methodology uses all 12 monthly peaks, but the demand values are weighted by the marginal cost of power in each month. Mr. Kalich identified the Aurora On-Peak Prices included in his pro forma power supply workpapers as the appropriate monthly marginal values to use for weighting peak demand. This methodology emphasizes the higher cost months (which may or may not be the highest peak months) without allowing the potential for free ridership that occurs when not all months are represented in the demand allocation factor.

Q. What were the results of Scenario 3?

A. Please see Page 3 of Exhibit 11, Schedule 5 which shows key results of alternative Scenario 3, as well as a comparison to the Base Case results. This methodology increased cost responsibility moderately for Residential, slightly for: General, Extra Large General 25P, and Street and Area Lights while it reduced cost responsibility moderately for Large General, Extra Large General 25, and Pumping.

Q. Are there any common implications from the results of all the cost of service studies?

A. Please see Table 2 which shows the Return Ratio from each of the studies:

<u>Table No. 2:</u>

Customer Class	Base Case	Scenario 1	Scenario 2	Scenario 3
Return Ratio				
Residential Service Schedule 1	0.82	0.82	0.75	0.81
General Service Schedules 11/12	1.52	1.52	1.53	1.52
Large General Service Schedules 21/22	1.09	1.09	1.16	1.11
Extra Large General Service Schedule 25	0.88	0.88	0.98	0.91
Extra Large General Service Clearwater Paper Schedule 25P	0.94	0.95	1.06	0.94
Pumping Service Schedules 31/32	0.96	0.96	1.22	1.08
Lighting Service Schedules 41 - 49	1.54	1.53	1.49	1.52
Total Idaho Electric System	1.00	1.00	1.00	1.00

All of the studies indicate Residential Service Schedule 1 under-recovers assigned costs more than any other group and both General Service Schedules 11/12 and Lighting Service Schedules 41 – 49 over-recover their assigned costs by a considerable amount. Results vary for the other rate groups, but they are all relatively close to providing the overall return for the Idaho electric system.

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

A. Yes.