Exh. TLK-1T

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BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-20_____

DIRECT TESTIMONY OF

TARA L. KNOX

REPRESENTING AVISTA CORPORATION

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 the 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 regulatory cost of service model 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 revenue normalization adjustments 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 two exhibits. Exh. TLK-2 presents the electric cost of service study results in the form of the Electric cost of service template provided by the Commission in accordance with WAC 480-85-040(1). Exh. TLK-3 presents a summary of AMI costs and benefits components of the electric cost of service study.

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

A. Yes, they were.

II. SUMMARY

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 Schedules 01/02 are under parity as the class provides significantly less than the overall rate of return under present rates. All other classes (General Service

Schedules 11/12, Large General Service Schedules 21/22, Extra Large General Service Schedule 25, Pumping Schedules 30/31/32 and Street and Area Lighting Service Schedules 41 – 48) are over parity as they provide more than the overall rate of return under present rates. Table No. 1 below shows the rate of return and the relationship of the customer class return to the overall return (relative return ratio) at present rates as well as the revenue-to-cost parity ratio at present rates for each rate schedule:

Table No. 1 – Relative Rates of Return at Present Rates and Parity Ratio

Customer Class	Rate of Return	Return Ratio	Parity Ratio
Residential Service Schedules 01/02	1.71%	0.30	0.82
General Service Schedules 11/12	10.67%	1.89	1.24
Large General Service Schedules 21/22	10.96%	1.94	1.25
Extra Large General Service Schedule 25	9.13%	1.61	1.15
Pumping Service Schedules 30/31/32	6.32%	1.12	1.03
Lighting Service Schedules 41 - 48	7.88%	1.39	1.12
Total Washington Electric System	5.65%	1.00	1.00

Notably, the residential rate schedules (Schedules 01/02), general service rate schedules (Schedules 11/12) and large general service rate schedules (Schedules 21/22) are considerably further from unity in the cost study than the other rate schedules.

III. ELECTRIC REVENUE NORMALIZATION

Q. Would you please describe the electric revenue normalization adjustments included in Company witness Ms. Andrews' Electric Pro Forma Study?

A. Yes. Similar to the natural gas revenue normalization adjustment, sponsored by Company witness Mr. Anderson, there are three separate adjustments that normalize revenue as part of the electric revenue normalization adjustment:

1. Weather Normalization: Column 2.10 of Ms. Andrews' Exh. EMA-2, page 6 is a Commission Basis weather normalization restating adjustment. Revenues for this adjustment are based on rates that were in effect during the January 2019 through December 2019 test period, and kWh sales and revenues have been adjusted to reflect normal weather conditions. The weather-related revenues associated with the Company's electric Decoupling Mechanism are removed in this adjustment, as kWh sales and revenues have been normalized to reflect normal weather conditions.

2. Eliminate Adder Schedules: In addition to the weather normalization adjustment, Ms. Andrews' study also includes an Eliminate Adder Schedules restating adjustment in column 2.11 of Exh. EMA-2, page 6, which removes the impact of adder schedule revenues and related expenses during the January 2019 through December 2019 test period. Decoupling contra-revenues recorded in the test year associated with financial reporting revenue recognition limits on deferred revenue mechanisms are also eliminated in this adjustment for Commission Basis reporting purposes.

3. Pro Forma Revenue: The Pro Forma Revenue Normalization Adjustment in column 3.01 of Exh. EMA-2, page 8, adjusts January 2019 through December 2019 test period customers and usage for any known and measurable (pro forma) changes. In addition, the adjustment re-prices billed, unbilled, and weather adjusted usage at the base tariff rates approved in 2020, as if the April 1, 2020 base tariff rates were effective for the full 12-months of the test year.[1]

[1] Docket UE-190334.

<u>Weather Normalization</u>

Q. Please begin with the <u>first revenue normalizing</u> adjustment. What is the Commission Basis weather normalization adjustment?

A. Weather normalization is a required element of Commission Basis reporting pursuant to WAC 480-100-257. The intent of this adjustment is for Commission Basis adjusted revenues (and power supply costs) to reflect operations under normal temperature conditions during the reporting period.

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 12-months ended December 2019 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 regression analysis of 10 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 multiplied by the monthly test period number of customers, which is then multiplied by the difference between normal heating/cooling degree-days and actual heating/cooling degree-days. This calculation produces the change in kWh usage required to adjust existing loads to the amount expected if weather had been normal.

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 2009 through December 2018 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 International 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 1990 through 2019.

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

A. Yes. The process for determining the weather sensitivity factors and the monthly adjustment calculation are consistent with the methodology presented in Docket UE-190334. This methodology has been used in every case and Commission Basis Report since it was introduced in Docket UE-070804.

Q. What was the change in kWhs resulting from weather normalization for the 12-months ended December 2019 test year?

A. Weather was colder than normal during February, March, and October, but warmer than normal during June and August of the test year. Since electric usage is impacted by both heating and cooling, weather normalization required a reduction to usage for both cold weather during the winter/fall months and hot weather during the summer months. Overall, the adjustment to normal required the reduction of 229 heating degree-days during the heating season[2] and the reduction of 21 cooling degree-days during the summer season.[3] The annual total adjustment to Washington electric sales volumes was a deduction of 42,754,825 kWhs, which is approximately 0.75% of billed usage.

Q. What was the impact of this adjustment on restated results of operations?

A. The Commission Basis weather normalization adjustment decreased total electric revenues by ($3,836,000). The combined effect of netting the decrease to revenue against the decoupling revenue offset of $2,883,000, resulted in net weather adjustment revenue of ($953,000).[4] After an offsetting adjustment for revenue-related expenses and taxes, the weather normalization adjustment produced a decrease to net operating income of ($619,000), as shown below:

Table No. 2: - Summarize Weather Normalization Adjustment

General Business Revenue (Sales)	($3,836,000)
Other Revenue (Decoupling Deferred)	$2,883,000
Total Revenue (Net Adjustment)	($953,000)
Less: Revenue Related Expenses	$169,000
Less: Income Tax Expense	$165,000
Net Operating Income	($619,000)

The cost of the weather-related load change is reflected in the "Authorized Power Supply" adjustment in column 2.18 (page 7, Exh. EMA-2). This power supply adjustment also captures the test period load difference from the retail load included in the Energy Recovery Mechanism (ERM) base approved by Docket UE-170485. Both the difference from authorized to actual 2019 loads and the weather normalization adjustment to loads are multiplied by the ERM Retail Revenue Adjustment Rate and then added to the May 1, 2018

2 The heating season includes the months of January through June and October through December.
3 The summer season normally 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.
4 The Decoupling Mechanism went into effect January 1, 2015.

ERM base costs. This process matches power supply costs with the power supply revenue per kWh embedded in present rates thereby maintaining the present authorized ERM base for Commission Basis results. For pro forma power supply cost determinations used in the "Pro Forma Power Supply" adjustment column 3.00P (page 8, Exh. EMA-2), the monthly system kWh weather adjustment values were provided to Company witness Mr. Kalich to incorporate into the 2019 normalized historical test year loads.

Eliminate Adder Schedules

Q. Moving on to the second revenue normalizing adjustment, what is the purpose of the Eliminate Adder Schedules restating adjustment?

A. The Eliminate Adder Schedules adjustment removes both the revenues and expenses associated with all adder schedule rates not accounted for in other adjustments. These items are recovered/rebated by separate tariffs and therefore are not part of base rates. The items eliminated from the test year include: Schedule 59 Residential Exchange credit, Schedule 74 Tax Reform Temporary rebate, Schedule 75 Decoupling rate adjustment, Schedule 89 Fixed-Income Senior and Disabled Residential Service Discount rate adjustment, Schedule 91 Demand Side Management rate adjustment, Schedule 92, Low Income Rate Assistance Program rate adjustment, the unbilled portion of Schedule 93 Energy Recovery Mechanism rate adjustment, Schedule 95 Optional Renewable Power rate, and the unbilled portion of Schedule 98 Renewable Energy Credit Revenue Mechanism credit.

Decoupling contra-revenues recorded in the test year associated with financial reporting revenue recognition limits on deferred revenue mechanisms are also eliminated in this adjustment for Commission Basis reporting purposes.

Q. What was the impact of the Eliminate Adder Schedule adjustment on restated results of operations?

A. The Eliminate Adder Schedule adjustment results in an equal and offsetting reduction to both revenue and expense and has no impact on net income unless contra-decoupling entries were recorded in the test year. For the 2019 test year, an electric contra-decoupling entry increased revenue $1,397,000. Elimination of this entry decreased net income ($1,104,000).

The billed portion of Schedules 93 and 98 are eliminated in the Eliminate WA Power Cost Deferral adjustment 2.15 on page 7 of Exh. EMA-2, and Schedule 58 Municipal Tax Adjustment is eliminated in the Eliminate B&O Taxes adjustment 2.01 on page 5 of Exh. EMA-2. After these adjustments the Restated Total General Business revenue (column R-Total on page 7 of Exh. EMA-2) represents weather normalized <u>base</u> rate revenue received during the 12-months ended December 31, 2019 test period (including decoupling deferred revenue not explained by weather).

<u>**Pro Forma Revenue**</u>

Q. Please describe the purpose of the <u>third revenue normalizing</u> adjustment, the Pro Forma Revenue Normalization adjustment.

A. The purpose of the Pro Forma Revenue Normalization adjustment (3.01) is to restate revenue on a forward-looking basis. This is accomplished by re-pricing test year normalized billing determinants (including unbilled and weather adjustments, as well as any known and measurable changes to the test year loads and customers) to reflect revenues for the January 2019 through December 2019 test period, as if the base tariff rates approved in

Docket UE-190334 effective April 1, 2020 had been in effect for the full 12 months of the test period.[5]

Q. What is the impact of the Pro Forma Revenue Normalization adjustment?

A. The Pro Forma Revenue Normalization adjustment increases general business revenue by $26,639,000. The combined effect of the increase to revenue from rates with elimination of both the 2019 restated decoupling deferred revenue of (-$10,789,000) and a true-up to the Tax Reform provision for rate refund booked in 2019 (+$181,000), resulted in a total pro forma revenue adjustment increase of $16,031,000. After an offset for revenue-related expenses and taxes, Washington net operating income increased $11,740,000, as shown below and in column 3.01 on page 8 of Exh. EMA-2.

<u>Table No. 3 – Summarize Revenue Normalization Adjustment</u>

General Business Revenue (Sales)	$26,639,000
Other Revenue (Eliminate Decoupling Deferred)	($10,789,000)
Other Revenue (Eliminate Provision for Refund)	$181,000
Total Revenue (Net Adjustment)	16,031,000
Less: Revenue Related Expenses	($1,170,000)
Less: Income Tax Expense	($3,121,000)
Net Operating Income	$11,740,000

<u>IV. ELECTRIC COST OF SERVICE</u>

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

[5] The Pro Forma Normalized Revenue does not include any pro formed decoupling deferred revenue. The decoupling base will be updated with the rates approved for this case based on the same usage and customers used to determine revenue from present rates in this adjustment.

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.

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 Exh. TLK-2 is based on the 12-months ended December 2019 test year pro forma results of operations presented by Ms. Andrews as Exh. EMA-2.

<u>Cost of Service Rulemaking</u>

Q. Are Cost of Service studies a required component of general rate case filings?

A. Yes. WAC 480-07-510(6), which discusses cost studies in general rate proceeding filings, was recently amended by General Order R-599 on July 7, 2020 to state that a company's initial general rate case filing must include a cost of service study that complies with the new chapter WAC 480-85.

Q. Was Avista a party to the generic cost of service collaborative that culminated in the Dockets UE-170002 and UG-170003 rulemaking and General Order R-599?

A. Yes. Commission Staff initiated the generic cost of service collaborative in 2017 in response to the Final Order in Avista's 2016 general rate proceeding (Dockets UE-

160228 and UG-160229). Avista participated in Staff's information gathering efforts and multiple workshops over three years as the collaborative evolved into the UE-170002 and UG-170003 rulemaking proceeding.

Q. What was the intended purpose of the collaborative and rulemaking?

A. The stated purpose of establishing the collaborative was to "provide an opportunity to establish greater clarity and some degree of uniformity in cost of service studies going forward".[6] The intention was refined and evolved over the course of the collaborative into the purpose stated as WAC 480-85-010:

> (1) The purpose of these rules is to establish minimum filing requirements for any cost of service study filed with the commission. These rules are designed to streamline, improve, and promote efficiency in analyzing rate cases, clarity of presentation, and ease of understanding. The minimum filing requirements will allow for comparisons of cost of service studies.

Q. Have the rules set forth in WAC 480-85 accomplished these goals?

A. Yes, I believe they have. The Commission-provided presentation templates that establish a consistent framework for comparison among studies provide clarity around the level of detail desired for exhibits. The methodology requirements streamline analysis by promoting consistent functionalization, classification, and allocation expectations. Staff should be commended for three years of hard work attempting to establish consensus among all the interested parties.

<u>Study Inputs – Load Study</u>

Q. Has the Company complied with all requirements of WAC 480-85?

A. Other than a possible conflict with section 050 discussed below, the Company

[6] Dockets UE-160228 and UG-160229 (consolidated), Final Order 06, pages 57-58.

believes the electric cost of service study presented in this filing meets all the requirements set forth in WAC 480-85. With that said, the requirements of WAC 480-85 have required extensive modifications to the cost of service model in order to meet both the presentation requirements and new data requirements associated with the allocation methods within section 060. The Company has interpreted the new requirements to the best of our ability and used the best available sources of information to us at the time of filing when preparing the cost of service study.

Q. What is the potential issue with WAC 480-85-050?

A. WAC 480-85-050(1) requires usage data for the study to come from the best available source, preferably advanced metering technology (AMI). The Company is presently completing implementing AMI for its Washington customers, as discussed by Company witnesses Ms. Rosentrater and Mr. DiLuciano. As implementation was just beginning during the 2019 test year, consistent hourly data representative of all customers during the test year is not available. Therefore, the Company falls under sub-section (d) requiring the use of a load study. Finally, Section (2) requires that usage data may not be older than five years.

As required by rule, the Company has utilized the best available source for usage data, namely 2019 billing data. At the present time hourly electric usage data is not available. Consequently, hourly demand estimates for use in developing all demand allocation factors relied primarily on 2019 billed usage data shaped based on the most recent load study. Consistent with recent cost of service studies prepared by the Company, hourly shaping was estimated using the relationship between average monthly kWh and hourly kW from the Company’s most recent electric load study applied to 2019 monthly billed data (average monthly kWh) as this is the best information available to the Company. The time period measured in the Company's most recent electric load study was 12-months ended June 30, 2014. That time period is more than five years earlier than the tes1t year by six-months. Out of an abundance of caution, the Company is filing a petition for limited exemption from WAC 480-85-050(2) concurrent with this filing for the continued use of its 2014 electric load study in this proceeding.

Q. Why has the Company not performed an electric load study since 2014?

A. Prior to the decision to pursue AMI, the Company policy was to perform an electric load study every five years which would have initiated a new study to commence with January 2019 meter readings. In 2018 the decision was made to defer the next load study until AMI implementation was complete. As stated in the Company's comments in Dockets UE-170002 and UG-170003 on March 27, 2020:

> The Company does not believe that conducting an expensive new load study prior to the completion of its AMI meters project, likely by a third-party entity, would be a prudent use of resources for customers to incur given the imminent availability of the AMI data. The Company asks that there be flexibility in this type of situation as the Company completes its transition to full deployment of AMI meters." (General Order R-599 Appendix A, page 6)

Q. Did Commission Staff provide a response to the Company's comments requesting transition flexibility during the rulemaking process?

A. Yes. On page 1 of Appendix A to the adoption Order, Staff stated that it "understands the concerns of stakeholders about implementation and will ask that the Commission take it into consideration."

Q. Do you believe that if the Company would have conducted a more recent load study it would have a material impact on the results of the cost of service study in this proceeding?

A. No. While it is reasonable to assume that a more recent load study would reflect changes to the hourly demand estimates used in developing the demand allocation factors, the Company does not believe this would have a material effect on the directional accuracy of the study's results given that the majority of rate schedules are significantly above or below rate parity.

<u>Methodology</u>

Q. Does the Electric Base Case cost of service study utilize the same methodology from the Company's last electric case in Washington?

A. No, the Base Case cost of service study was prepared using the methodology outlined in WAC 480-85-060 resulting from the rulemaking approved in July 2020. This methodology differs from the cost studies the Company has provided in previous electric general rate cases.

Q. Would you please explain the cost of service study presented in Exh. TLK-2?

A. Yes. Exh. TLK-2 presents the results of the cost of service study in the form of the Electric cost of service template available from the commission in compliance with WAC 480-85-040(1). Electronically the template consists of five workbook tabs that are presented as separate sections in this exhibit. Section A is the Revenue Requirement Cross-reference which shows Ms. Andrews revenue requirement development (Exh. EMA-2) expressed at the FERC Account level to facilitate assignment of costs to customer rate classes in the study. Section B presents the FERC Account level cost of service results for all customer rate classes. Section C shows the allocation factors used to assign each type of cost to the customer rate classes. Section D is a summary of the revenue requirement adjustments shown in Section A and is comparable to page 12 of Ms. Andrews Exh. EMA-2. Finally, Section E is a high-level summary of the cost of service results showing the Parity ratios at present rates and Revenue-to-Cost ratios at proposed rates.

The fully functional Excel model supporting this exhibit that calculates the cost of service results, along with supporting schedules, have been included in their entirety electronically and hard copy in the workpapers accompanying this case. While there are macros to facilitate printing certain workpapers, no macros are integral to the cost of service model calculations.

Q. How are generation costs treated in this study?

A. In this study generation costs (production plant related rate base and expenses including operation and maintenance, depreciation and taxes) have been classified as energy or demand related based on a renewable future peak credit ratio, with net power costs considered 100% energy. The demand-related portions were allocated to customer rate classes based on the average of 12 system coincident peaks determined from power supply native load excluding renewable generation. The energy-related portions were allocated to customer rate classes based on annual energy usage at the point of generation.

The renewable future peak credit method compares the cost of battery storage (demand) to wind turbine (energy) derived from the Company's 2020 IRP at 2022 cost assumptions. This analysis resulted in 67.17% demand and 32.83% energy peak credit allocation (proportions exclusive of energy-related net power costs).

Q. Has this methodology been used in Avista's prior cost studies?

A. No. In prior electric cost of service studies, the Company utilized a load-factor peak credit method that was applied to all generation costs (including net power costs). The new methodology increases the proportion considered demand related costs. In prior studies, the demand allocation factor was based on the average of 12 system coincident peaks. Excluding load from renewable generation changes the time of the system peaks with a moderate effect on the resulting allocation factor.

Q. How are transmission costs treated in this study?

A. All transmission costs (except Transmission of Electricity by Others and revenue from Transmission of Electricity for Others which are part of net power costs included in the Energy Recovery Mechanism) are considered demand-related and allocated to customer rate classes by the average of 12 system coincident peaks.

Q. Is this methodology different from prior Avista electric cost of service studies?

A. Yes. In prior cases the transmission function was treated as an extension of production costs and as such was subject to the load factor peak credit. The new methodology increases the proportion considered demand related costs.

Q Please identify any changes to the methodology associated with distribution costs?

A. No change was required for the direct assignment of distribution substations, poles, conduit, and wires as the Company has consistently directly assigned costs to the extra-large general service customer class based on the load ratio share of substations they are fed from.

The methodology set forth in WAC 480-85-060 utilizes some different allocation factors for the customer rate classes that are not directly assigned. For distribution substations, this study allocates these classes by the average of the relative share of the summer distribution system coincident peak and the relative share of the winter distribution system coincident peak. In prior cases Avista had used the average of 12 monthly non-coincident peaks to assign these costs. Distribution line transformer costs are allocated to customers who receive power at secondary voltage by the relative ratio of transformers at current installation costs except for the street and area lighting class which is assigned its proportion of noncoincident peak to the sum of noncoincident peaks for all secondary voltage customers. The Company's prior studies used noncoincident peak of secondary voltage customers to allocate line transformer costs.

For poles, conduit, and wires this study allocates the customer groups (not directly assigned) by the average of 12 monthly distribution system noncoincident peaks separately for primary system and secondary system customers. This method is not a change from prior Avista electric cost of service studies.

Q. How are customer-related distribution costs treated in this study?

A. Service line costs and meter costs are allocated to customer rate classes by customer count multiplied by installed cost of new service lines and meters, respectively. Customer service and billing operating expenses are allocated by customer counts weighted as merited. In the Company's prior electric cost of service studies, service line costs were allocated by average secondary customer counts without weighting. The methodology did not change for the other customer-related distribution costs.

Q. How are administration and general operating expenses and general plant costs treated in this study?

A. Property insurance and taxes are functionalized and allocated based on plant in service. Pensions and employee insurance expenses are allocated based on salary and wages. FERC fees are identified and allocated based on energy consumption. Revenue based fees, uncollectible accounts expenses, and excise taxes are allocated by relative share of total revenue. Other administrative and general costs which can be directly associated with production, transmission, distribution, or customer relations functions based on Company department (Expenditure Organization) are directly assigned to those functions and then allocated to customer class by the relevant plant or number of customers associated with the function.

The remainder of administrative and general expenses and general plant costs are considered common costs and are allocated to customer rate classes by the Company's four-factor allocator. This allocation factor is the cost of service equivalent of the four-factor allocator used in the Company's results of operations reporting. The four-factor has historically been utilized by the Company to allocate common operating costs and plant between states (Washington, Idaho, and Oregon) and among services (electric and natural gas) for purposes of the Company's Commission Basis results of operations.

Q. Please describe the components of the four-factor.

A. The four-factor is comprised of the following four equally weighted components:

- Direct O&M excluding resource costs and labor
- Direct O&M labor
- Number of customers
- Net direct plant

Q. Please describe the benefits of the four-factor allocator.

A. There are two primary benefits of the four-factor. First, it reflects a variety of relationships that are consistent with the specific costs and plant items which are recognized as serving multiple functions. Second, it provides consistency and balance between the way common costs are allocated for purposes of Commission Basis results of operations and the cost of service study used in general rate cases.

Q. Is this methodology different from prior Avista electric cost of service studies?

A. The specific treatment of items called out in WAC 480-85-060 Table 2, as well as the assignment to function, is consistent with prior Avista electric cost of service studies. However, the treatment of common costs in prior electric studies was entirely based on methods approved for Puget Sound Energy in Docket UE-920499. Moving to the four-factor assignment for common costs aligns the Company's electric cost of study with the common cost allocation utilized for natural gas cost of service in recent cases.

Q. Did the Company prepare an analysis of Intangible Plant accounts while preparing this Cost of Service Study?

A. Yes. Account 302 was segregated between generation-related hydro relicensing agreements, transmission-related forest use permits, and distribution-related department of transportation franchises. Account 303.000 was segregated between transmission-related communication agreements, distribution-related communication agreements and miscellaneous intangible assets considered common costs. Account 303.120 and 303.121 software costs are associated with the meter data management system (MDM) and advanced metering infrastructure (AMI) project. In this study the MDM and AMI software costs have been allocated by number of customers. An analysis of Account 303.100 computer software by project is included in the Company workpapers. No additional functionalization resulted from the project level analysis. Common intangible plant costs have been allocated based on tangible plant. This treatment of intangible plant costs is consistent with the Company's past electric cost of service studies.

Rate Class Results

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

A. Exhibit No. TLK-2, Section E presents a high-level summary of the rate class results in the form required by the WAC 480-85-040(1) Electric cost of service template. Table No. 4 shows the rate of return and the relationship of the customer class return to the overall return (relative return ratio) in addition to the revenue-to-cost parity ratio at present rates for each rate schedule:

Table No. 4 – Electric Cost of Service Base Case Results

Customer Class	Rate of Return	Return Ratio	Parity Ratio
Residential Service Schedules 01/02	1.71%	0.30	0.82
General Service Schedules 11/12	10.67%	1.89	1.24
Large General Service Schedules 21/22	10.96%	1.94	1.25
Extra Large General Service Schedule 25	9.13%	1.61	1.15
Pumping Service Schedules 30/31/32	6.32%	1.12	1.03
Lighting Service Schedules 41 - 48	7.88%	1.39	1.12
Total Washington Electric System	5.65%	1.00	1.00

As can be observed from the above table, Residential service Schedules 01/02 show under-recovery of the costs to serve them. The Pumping service Schedules 30/31/32 are relatively close to unity with the overall return from present rates. The other customer classes show over-recovery of the costs to serve them (currently providing in excess of the requested rate of return). The summary results of this study were provided to Company witness Mr. Miller for consideration in the development of proposed rates.

V. AMI COSTS AND BENEFITS BY RATE CLASS

Q. Please describe the context for the AMI cost and benefit analysis within your testimony and exhibits?

A. As a part of Avista's Deferred Accounting Petition approved by the Commission in Dockets UE-170327 and UG-170328, in Attachment A to the Amended Petition Avista agreed to provide "a detailed analysis of AMI system costs and benefits relative to each customer rate class" as a part of its AMI Report, sponsored by Mr. DiLuciano. Given the proximity of the filing of the report, and this general rate case, Avista believed that such an analysis made more sense to the Commission and the Parties to review as an adjunct to our Cost of Service studies.

Q. Have you prepared a detailed analysis of AMI system costs and benefits relative to each customer rate class?

A. Yes, I have. Exh. TLK-3 presents a summary of the rate year AMI and MDM cost components embedded in the electric cost of service study followed by an estimate of the Washington electric share of total rate year cost reductions identified in the AMI Report. In this analysis, the rate class assignment of costs come directly from the cost of service model. The quantifiable benefits, which represent reductions to potential costs, are measured by their absence from the rate year revenue requirement. The Washington electric share of these cost reductions have been treated like common administrative and general costs to estimate their impact by rate class.

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

A. Yes.