BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-22_____

DIRECT TESTIMONY OF

MARCUS J. GARBARINO

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Marcus J. Garbarino and my business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as Manager of Regulatory Affairs in the Regulatory Affairs Department.

Q. What is your educational background and professional experience?

A. I am a 2008 graduate of Eastern Washington University with a Bachelor of Arts degree in Business Administration, majoring in Accounting, and became a Certified Public Accountant in May 2011. After spending four years in the public accounting sector, I joined Avista in April 2012 as a Resource Accounting Analyst. In July 2014, I moved to the Company's Internal Audit Department as a Senior Internal Auditor until joining the Regulatory Affairs group in October 2020 as Manager of Regulatory Affairs. My primary responsibilities include electric cost of service, customer usage and revenue analysis, and preparing annual Purchased Gas Adjustment filings for all jurisdictions, amongst other things.

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

A. My testimony and exhibit present the Company's electric revenue normalization adjustments and the electric cost of service study prepared for this filing. The results of this study were provided to Company witness Mr. Miller and were used to inform the spread of the proposed increase by service schedule. Company witness Mr. Anderson testifies regarding the natural gas cost of service study and the natural gas revenue normalization adjustment. A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exh. MJG-2 which 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). This exhibit was prepared by me and consists of summaries of information derived from the Electric Cost of Service Study.

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. The Special Contract (Schedule 25I)[1] is currently at parity and all other classes (General Service (Schedules 11/12), Large General

[1] This pertains to the recently approved Special Contract with Inland Empire Paper (IEP) in Docket No. UE-200900.

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, Return Ratio and Parity Ratio

Customer Class	Rate of Return	Return Ratio	Parity Ratio
Residential Service Schedules 01/02	2.02%	0.38	0.84
General Service Schedule 11/12	9.72%	1.81	1.22
Large General Service Schedules 21/22	10.35%	1.93	1.25
Extra Large General Service Schedule 25	9.71%	1.81	1.20
Extra Large General Service Schedule 25I	4.96%	0.93	1.00
Pumping Service Schedules 30/31/32	6.57%	1.23	1.06
Lighting Service Schedule 41 - 48	6.44%	1.20	1.03
Total Washington Electric System	5.36%	1.00	1.00

Notably, the Residential Service (Schedules 01/02), General Service (Schedules 11/12), Large General Service (Schedules 21/22), and Extra Large General Service (Schedule 25) 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 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 7 is a Commission Basis weather normalization restating adjustment. Revenues for this adjustment are based on rates that were in effect during the October 2020 through September 2021 test period, and kWh sales and revenues have been adjusted to reflect normal weather conditions. The weather-related deferred 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 7, which removes the impact of adder schedule revenues and related expenses during the October 2020 through September 2021 test period. Decoupling contra-revenues recorded in the test period associated with financial reporting revenue recognition limits on deferred revenue mechanisms are also eliminated in this adjustment for Commission Basis reporting purposes.[2]

3. Pro Forma Revenue: The Pro Forma Revenue Normalization Adjustment in column 3.01 of Exh. EMA-2, page 9, adjusts October 2020 through September 2021 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 2021, as if the October 1, 2021, base tariff rates were in effect for the full 12-months of the test period.[3]

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[2] There were no decoupling contra-revenues recorded during the test period.
[3] Dockets UE-200900 et. al.

Weather Normalization

Q. Please begin with the first revenue normalizing 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 September 2021 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 2010 through December 2019, 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 1991 through 2020.

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 Dockets UE-200900 et. al. 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 September 2021 test period?

A. With the exception of February, weather was warmer than normal during all months of the heating season[4] and warmer than normal during all months of the summer season[5] in the test period. Since electric usage is impacted by both heating and cooling,

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

[5] 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.

weather normalization required an increase to usage for warm weather during the winter/fall months and a reduction to usage for hot weather during the summer months. Overall, the adjustment to normal required an increase of 435 heating degree-days during the heating season and the reduction of 419 cooling degree-days during the summer season. The annual total adjustment to Washington electric sales volumes was a deduction of 89,970,709 kWhs, which is approximately 1.6% 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 ($8,167,000). The combined effect of netting the decrease to revenue against the decoupling revenue offset of $6,175,000, resulted in net weather adjustment revenue of ($1,992,000).[6] After an offsetting adjustment for revenue-related expenses and taxes, the weather normalization adjustment produced a decrease to net operating income of ($1,291,000), as shown below:

Table No. 2: - Weather Normalization Adjustment Summary

General Business Revenue (Sales)	($8,167,000)
Other Revenue (Decoupling Deferred)	$6,175,000
Total Revenue (Net Adjustment)	($1,992,000)
Less: Revenue Related Expenses	$358,000
Less: Income Tax Expense	$343,000
Net Operating Income	($1,291,000)

The cost of the weather-related load change is reflected in the "Authorized Power Supply" adjustment in column 2.19 (page 8, Exh. EMA-2). This power supply adjustment also captures the test period load difference from the retail load included in the Energy Recovery

[6] The Decoupling Mechanism went into effect January 1, 2015.

Mechanism (ERM) base approved by Docket UE-170485.[7] Both the difference from authorized to actual loads for the 12-months ended September 30, 2021 and the weather normalization adjustment to loads are multiplied by the ERM Retail Revenue Adjustment Rate and then added to the 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 9, Exh. EMA-2), the monthly system kWh weather adjustment values were provided to Company witness Mr. Kalich to incorporate into the 12-months ended September 30, 2021 normalized historical test period loads.

Eliminate Adder Schedules

Q. Moving on to the <u>second revenue normalizing</u> 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 period include: Schedule 59 Residential Exchange credit, 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

[7] UE-190334 did not include an update to the ERM base due to the concurrent power cost workshops. The ERM base from UE-200900 went into effect October 1, 2020, after the end of the test period.

portion of Schedule 93 Energy Recovery Mechanism rate adjustment, Schedule 94 2015 General Rate Case Credit, Schedule 95 Optional Renewable Power rate, and the unbilled portion of Schedule 98 Renewable Energy Credit Revenue Mechanism credit.

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 period. As noted in footnote 1, There were no decoupling contra-revenues recorded during the test period.

The billed portion of Schedules 93 and 98 are eliminated in the Eliminate WA Power Cost Deferral adjustment 2.16 on page 8 of Exh. EMA-2, and Schedule 58 Municipal Tax Adjustment is eliminated in the Eliminate B&O Taxes adjustment 2.01 on page 6 of Exh. EMA-2. After these adjustments the Restated Total General Business revenue (column R-Total on page 8 of Exh. EMA-2) represents weather normalized base rate revenue received during the 12-months ended September 30, 2021 test period (including decoupling deferred revenue not explained by weather).

Pro Forma Revenue

Q. Please describe the purpose of the third revenue normalizing 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 period normalized billing determinants (including unbilled and weather adjustments, as well as any known and measurable changes to the test period loads and customers) to reflect revenues for the October 2020 through September 2021 test period, as if the base tariff rates approved in Dockets UE-200900 et. al. effective October 1, 2021, had been in effect for the full 12 months of the test period.[8]

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

A. The Pro Forma Revenue Normalization adjustment increases general business revenue by $14,875,000. The combined effect of the increase to revenue from rates with elimination of the restated decoupling deferred revenue of ($1,512,000) resulted in a total pro forma revenue adjustment increase of $13,363,000. After an offset for revenue-related expenses and taxes, net operating income increased $10,041,000, as shown below and in column 3.01 on page 9 of Exh. EMA-2.

Table No. 3 – Summarize Revenue Normalization Adjustment

General Business Revenue (Sales)	$14,875,000
Other Revenue (Eliminate Decoupling Deferred)	($1,512,000)
Total Revenue (Net Adjustment)	$13,363,000
Less: Revenue Related Expenses	($653,000)
Less: Income Tax Expense	($2,669,000)
Net Operating Income	$10,041,000

IV. ELECTRIC COST OF SERVICE

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

[8] 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.

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.

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. MJG-2 is based on the 12-months ended September 2021 test period pro forma results of operations for Rate Year 1 presented by Ms. Andrews as Exh. EMA-2.

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 amended by General Order R-599 on July 7, 2020 to state that a utility's initial general rate case filing must include a cost of service study that complies with the new chapter WAC 480-85.

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

A. Yes, the Company believes the electric cost of service study presented in this filing meets all the requirements set forth in WAC Chapter 480-85. In the Company's last case, Dockets UE-200900 et. al., Staff witness Ms. Jordan was asked, "Did the Company comply with the requirements of Chapter 480-85 WAC?" and responded "Yes. However, the

Company requested, and the Commission authorized, a one-time exemption from WAC 480-85-050(2) for the electric cost study and from WAC 480-85-050(1) for the natural gas cost study"[9].

Q. Has the issue associated with the exemption Ms. Jordan referenced been resolved?

A. Yes. The prior case exemption associated with WAC 480-85-050 that requires usage data for the study to come from the best available source, preferably advanced metering technology (AMI) has been resolved. In this case, the Company's recently-completed installation of AMI for its Washington customers enabled the use of AMI data to complete our most recent load study for the 12 months ended September 30, 2021 period.

Other than the source of the load study, the cost of service study is consistent with the study filed in Docket No. UE-200900. Therefore, we believe we are in full compliance with WAC 480-85.

Methodology

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

A. Yes, the Base Case cost of service study was prepared using the same methodology used in our previous rate case, which complies with the methodology described in WAC 480-85-060.

Q. Please explain the cost of service study presented in Exh. MJG-2?

A. Exh. MJG-2 presents the results of the cost of service study in the form of the

[9] Exh. ELJ-1T, at 7:7-10 in Elaine L. Jordan Testimony (UE-200900)

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 for Rate Year 1 (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 13 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"[10] 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

[10] A macro is a function to automate an action or task within an Excel workbook.

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 2021 Electric IRP, at 2023 cost assumptions. This analysis resulted in 66.2% demand and 33.8% energy peak credit allocation (proportions exclusive of energy-related net power costs). Use of the renewable future peak credit ratio is in accordance with Commission rules which were adopted with an eye to the future where renewable resources provide energy, but reliable capacity is going to be problematic. The treatment is consistent with the methodology presented in Dockets UE-200900 et. al.

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. The treatment is consistent with the methodology presented in Dockets UE-200900 et. al.

Q. How are distribution costs treated in this study?

A. This study follows methodology set forth in WAC 480-85-060 utilizing allocation factors for the customer rate classes that are not directly assigned, and directly assigning distribution substations, poles, conduit, and wires to the Extra Large General Service schedules 25 and 25I based on the load ratio share of substations they are fed from. 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. 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. 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. These methods are consistent with the methodology presented in Dockets UE-200900 et. al.

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

A. Service line costs and meter costs are allocated to customer rate schedules 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 and weighted, if appropriate. This method is consistent with prior Avista electric cost of service studies.

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. This method is consistent with the methodology presented in Dockets UE-200900 et. al.

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 and 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.

Q. How were new Schedules 13 and 23 incorporated in the Company's filed electric cost of service study?

A. Schedule's 13 and 23 were approved in Docket UE-210182 with an effective date of April 26, 2021[11]. Given the limited number of customers that have taken service on these schedules since they were approved, the Company has included the limited amount of associated costs with Schedule's 11 and 21 for purposes of the revenue adjustment and cost of service. The Company anticipates having enough data in its next general rate case filing to separate these customers into their own rate class for cost of service analysis.

[11] Schedule 13 is Optional Commercial Electric Vehicle General Service Schedule 13 and Schedule 23 is Optional Commercial Electric Vehicle Large General Service Schedule 23. Both are "time of use" rate schedules for electric vehicle charging stations that are separately metered.

Q. How was the Special Contract approved in the Company's last general rate case, Dockets UE-200900 et. al., incorporated into the filed cost of service study?

A. The Special Contract[12] is shown as a separate rate class (Schedule 25I) receiving cost assignment based on test period usage characteristics. In the Partial Multiparty Settlement Agreement approved by the Commission under Dockets UE-200900 et. al, Section 11.b stated "the Settling Parties Settling Parties agree that the IEP special contract revenue adjustment will be recovered from all other electric customers based on the spread of the return of the AFUDC deferral balance." The Company replicated this approach for incorporation of the Special Contract into the filed cost of service study by including a "Special Contract Common Cost Adjustment" directly assigned to Schedule 25I that is offset by a "Reallocated Common Cost Adjustment" based on allocated rate base. After all other costs were assigned based on the methodology described earlier in my testimony, the amount of the adjustment and re-allocation was manually determined as the amount to cause special contract revenue at proposed rates (per Special Contract rate update formula Article 3.2) to result in costs equal to revenue, or unity. The Special Contract is included in the cost study as its own rate class, such that revenue from the special contract formula rates exactly equal costs, thereby avoiding any implied subsidy in the cost study results for all other customer classes.

Q. Has the Company met with interested parties and reached an agreement on how the Special Contract has been incorporated into the filed cost of service study?

A. The final order of the Company's last general rate case approved the Special Contract with conditions, including that the Company was to meet with interested parties to

[12] Entered into with Inland Empire Paper (IEP) and approved by the Commission in Docket UE-200900.

discuss how the Special Contract will be treated in future cost of service studies and file a report within 180 days of the order (by April 1, 2022), indicating whether interested parties have reached an agreement. Since the final order, the Company has provided a proposal of how the Special Contract might be incorporated into future cost of service studies, describing the method applied in the cost of service study in this filing, to Commission Staff and the Inland Empire Paper Company (IEP). It is the Company's understanding that IEP is supportive of the proposal and we have not received comments from Commission Staff. We will meet with all interested parties in the first quarter of 2022 to further discuss the proposal and report back to the Commission whether an agreement has been reached. If those discussions result in agreement between interested parties that changes the method for incorporating the Special Contract into the cost of service study from what has been proposed in this case, the Company will incorporate the changes and provide an updated cost of service study at that time.

Rate Class Results

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

A. Exhibit No. MJG-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:

<u>Table No. 4 – Electric Cost of Service Base Case Results</u>

Customer Class	Rate of Return	Return Ratio	Parity Ratio
Residential Service Schedules 01/02	3.79%	0.52	0.84
General Service Schedule 11/12	11.82%	1.62	1.22
Large General Service Schedules 21/22	12.54%	1.72	1.25
Extra Large General Service Schedule 25	12.22%	1.67	1.20
Extra Large General Service Schedule 25I	7.35%	1.01	1.00
Pumping Service Schedules 30/31/32	8.51%	1.16	1.06
Lighting Service Schedule 41 - 48	7.66%	1.05	1.03
Total Washington Electric System	7.31%	1.00	1.00

As can be observed from the above table, Residential Service (Schedules 01/02) shows under-recovery of the costs to serve them. The single large Special Contract (Schedule 25I), Pumping service (Schedules 30/31/32), and Lighting Service (Schedules 41 - 48) are relatively close to unity with the overall return from present rates. The other customer classes, however, show over-recovery of the costs to serve them (currently providing in excess of the <u>requested</u> rate of return).

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

A. Yes.