BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UG-22_____

DIRECT TESTIMONY OF

JOEL C. ANDERSON

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Joel C. Anderson. My business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Regulatory Analyst in the Regulatory Affairs Department.

Q. Would you briefly describe your educational background and professional experience?

A. I am a 2005 graduate of Eastern Washington University with a Bachelor's degree in Business Administration, majoring in Finance. In 2012, I became a Certified Public Accountant in the State of Washington. I joined the Company in January 2013, after spending seven years working in various accounting positions in the banking industry. I started with Avista as an Internal Auditor. In January 2016, I joined the Regulatory Affairs Department as a Regulatory Analyst. In my current role as a Regulatory Analyst, I am responsible for the Company's natural gas cost of service studies in all jurisdictions, among other things.

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

A. My testimony presents the natural gas cost of service study and revenue normalization adjustment 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. Garbarino will testify regarding the electric cost of service study and the electric revenue normalization adjustment. A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits that accompany your testimony?

A. Yes. I am sponsoring Exh. JCA-2 related to the natural gas cost of service study. This exhibit was prepared by me and consists of summaries of information derived from the Cost of Service Study.

II. SUMMARY

Q. Please briefly summarize your testimony related to the natural gas 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 cost of service study indicates that General Service Schedules 101/102 (serving mostly residential customers) and Transportation Schedule 146 are under parity as the classes provide less than the overall rate of return under present rates. The other classes, Large General and Interruptible Schedules (111/112/116, 131/132) are over parity as they provide more than the overall rate of return at present rates. Table No. 1 shows the rate of return and the relationship of the customer class return to the overall return (relative return ratio) at present rates for each rate schedule 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

Rate Schedule	Rate of Return	Return Ratio	Parity Ratio
General Service Schedule 101/102	4.57%	0.82	0.94
Large General Service Schedules 111/112	12.67%	2.22	1.49
Interruptible Sales Service Schedule 132	9.22%	1.62	1.24
Transportation Service Schedule 146	2.33%	0.41	0.73
Total Washington Natural Gas System	5.71%	1.00	1.00

III. NATURAL GAS REVENUE NORMALIZATION

Q. Would you please describe the natural gas revenue normalization adjustment included in Company witness Ms. Andrews's Natural Gas Pro Forma Study?

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

1. Weather Normalization and Gas Cost Adjustment: Column 2.10 of Ms. Andrews' Exh. EMA-3, 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 therm sales and revenues have been adjusted to reflect normal weather conditions. The weather-related revenues associated with the Company's natural gas Decoupling Mechanism are removed in this adjustment, as therm 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-3, page 7, which removes the impact of adder schedule revenues and related expenses during the October 2020 through September 2021 test period.

3. <u>Pro Forma Revenue Normalization</u>: The Pro Forma Revenue Normalization Adjustment in column 3.01 of Exh. EMA-3, 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 for 2021, as if the October 1, 2021 base tariff rates were effective for the full 12 months of the year.[1]

<u>Weather Normalization:</u>

Q. Beginning 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 480-90-257. The intent of this adjustment is for Commission Basis adjusted revenues and natural gas costs to reflect operations under normal temperature conditions during the reporting period.

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

A. Yes. As in past cases, the natural gas weather normalization adjustment is developed from a regression analysis of 10 years of billed usage-per-customer and billing period heating degree-day data. The resulting seasonal weather sensitivity factors (use-per-customer-per-heating-degree day) are multiplied by the monthly test period number of customers, which is then multiplied by the difference between normal and actual heating degree-days. This calculation produces the change in therm usage required to adjust existing

[1] Docket No. UG-200901

loads to the amount expected if weather had been normal.

Q. In the discussion of electric weather normalization sponsored by Mr. Garbarino, he indicated that the adjustment utilized sensitivity factors from the 10-year period January 2010 through December 2019. Is this true for natural gas as well?

A. Yes, the natural gas weather adjustment utilized updated weather sensitivity factors for the same 10-year period.

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

A. Normal heating degree-days are based on a rolling 30-year average of heating degree-days reported for each month by the National Weather Service for the Spokane 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 is consistent with the methodology presented in Docket UG-200901. This methodology has been used in every case since it was introduced in Docket UG-070805.

Q. What was the impact of natural gas weather normalization on the 12-months ended September 2021 test year?

A. Weather was warmer than normal during the October 2020 through September 2021 period. The adjustment to normal required an increase of 435 heating degree-days from

January through June and October through December.[2] The adjustment to sales volumes was an increase of 12,063,437 therms which is approximately 6.1 percent of billed usage.

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

A. The Commission Basis weather normalization adjustment increased total natural gas revenue by $8,279,000, which after the offsetting decrease to purchased gas expense of $4,812,000, resulted in an increase to distribution margin of $3,467,000. The combined effect of netting the increase to distribution margin against the decoupling revenue offset of $4,812,000, resulted in a net margin weather adjustment of $363,000.[3] After an offsetting decrease for revenue related expenses, the weather normalization adjustment produced no net operating income, as shown below:

Table No. 2: - Weather Normalization Adjustment Summary

General Business Revenue (Sales)	$	8,279,000
Other Revenue (Decoupling Deferred)	$	(4,812,000)
Total Revenue (Net Adjustment)	$	3,467,000
Less: Purchased Gas Expense	$	3,104,000
Distribution Margin Weather Adjustment	$	363,000
Less: Revenue Related Expenses	$	(363,000)
Less: Federal Income Tax	$	0
Net Operating Income	$	0

Eliminate Adder Schedules:

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

[2] Heating degree days that occur during July through September do not impact the natural gas weather normalization adjustment, as the seasonal sensitivity factor is zero for summer months.
[3] The Decoupling Mechanism went into effect January 1, 2015.

A. The Eliminate Adder Schedule adjustment removes both the revenues and expenses associated with all adder schedule rates, except current natural gas costs (Purchased Gas Cost Adjustment Schedule 150), since these items are recovered/rebated by separate tariffs and, therefore, are not part of base rates. The items eliminated include: Schedule 194 (2015 General Rate Case Credit), Schedule 175 (Decoupling Mechanism Rate Adjustment), Schedule 189 (Fixed-Income Senior & Disabled Residential Service Discount Rate Adjustment), Schedule 191 (Demand Side Management Rate Adjustment), Schedule 192 (Low Income Rate Assistance Program Rate Adjustment), and Schedule 155 (Gas Rate Adjustment). This adjustment also identifies and consolidates all the purchased gas cost related accounts into the "City Gate Purchases" line item in order to simplify the Pro Forma Revenue Normalization adjustment described below.

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

A. The Commission Basis Eliminate Adder Schedule adjustment results in an equal and offsetting reduction to both revenue and expense and has no impact on net income.

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

Q. Please describe the third revenue normalizing adjustment, the Pro Forma Revenue Normalization adjustment.

A. The purpose of the "Pro Forma Revenue Normalization" adjustment is to restate distribution revenue on a forward-looking basis and to remove natural gas costs. 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 year loads and customers) to reflect revenues for the October 2020 through September 2021 test period.

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

A. No, natural gas commodity costs previously shown as an equal and offsetting amount in both revenue and expense, have been removed from the Company's filing.

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

A. The Pro Forma Revenue Normalization adjustment increases total natural gas revenue by $44,946,000. After taking into account the offsetting effect of the decrease to revenue from rates with the elimination of both the restated decoupling deferred revenue $907,000 and transportation revenue of (-$296,000), this resulted in a total pro forma revenue adjustment increase of $6,746,000. After an offset for revenue-related expenses and taxes, Washington net operating income increased $6,871,000, as shown below, and in column 3.01 on page 9 of Exh. EMA-3.

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

General Business Revenue	$	(44,946,000)
Other Revenue (Eliminate Decoupling Deferred)	$	(907,000)
Other Revenue (Transportation)	$	296,000
Total Revenue (Net Adjustment)	$	(43,743,000)
Eliminate Purchased Gas Expense	$	50,489,000
Distribution Margin Adjustment	$	6,746,000
Revenue Related Expenses	$	1,952,000
Federal Income Tax	$	(1,827,000)
Net Operating Income	$	6,871,000

IV. NATURAL GAS COST OF SERVICE

Q. Please describe the natural gas cost of service study and its purpose.

A. A natural gas cost of service study is an engineering-economic study which separates the revenue, expenses, and rate base associated with providing natural gas service to designated groups of customers. The groups are made up of customers with similar usage characteristics and facility requirements. Costs are assigned in relation to each group's test period load and facilities requirements, resulting in an evaluation of the cost of 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 appropriate rate spread among the groups of customers.

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

A. The cost of service study provided by the Company as Exh. JCA-2 is based on the 12-months ended September 2021 test year pro forma results of operations for Rate Year 1 presented by Ms. Andrews in Exh. EMA-3.

Q. Please explain the basic concepts involved in performing a natural gas cost of service study.

A. There are three basic steps involved in a cost of service study: functionalization, classification, and allocation. First, the expenses and rate base associated with the natural gas system under study are assigned to functional categories. The FERC uniform system of accounts provides the basic segregation into production, underground storage, and distribution. Traditionally, customer accounting, customer information, and sales expenses are included in the distribution function and administrative and general expenses and general plant rate base are allocated to all functions. In this study I have created a separate functional category for common costs. Administrative and general costs that cannot be directly assigned to the other functions have been placed in this category.

Second, the expenses and rate base items are classified into three primary cost components: demand, commodity, and customer-related. Demand-related (capacity) costs are allocated to rate schedules based on design day peak demand. Commodity-related (energy) costs are allocated based on each rate schedule's share of commodity consumption. Customer-related items are allocated to rate schedules based on the number of customers within each schedule. The number of customers may be weighted by appropriate factors such as relative cost of metering equipment. In addition to these three cost components, any revenue-related expenses are allocated based on the proportion of revenues by rate schedule. The final step is allocation of the costs to the various rate schedules utilizing the allocation factors selected for each specific cost item. These factors are derived from usage and customer information associated with the test period results of operation.

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

A. Yes, the Company believes the natural gas cost of service study presented in this filing meets all the requirements set forth in WAC 480-85. In the Company's last case UE-200900, 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". 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 recently completed the installation of AMI for its Washington customers, and therefore used AMI data from the test year ending September 2021 in the demand study. This case presented the first opportunity to make use of a years' worth of AMI data. As such, we believe we are now in full compliance with WAC 480-85.

Methodology

Q. Does the Natural Gas Base Case cost of service study utilize the same methodology from the Company's last natural gas case in Washington?

A. Yes, the Base Case cost of service study was prepared using the same methodology used in our previous rate case and complies with WAC 480-85-060 resulting from the new cost of service rules approved in July 2020.

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

A. Exh. JCA-2 presents the results of the cost of service study in the form of the natural gas cost of service template available from the Commission in compliance with WAC 480-85-040(1). Electronically the template consists of six 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-3) 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. Section

E is a high-level summary of the cost of service results showing the Parity ratio at present rates and the Revenue-to-Cost ratio at proposed rates. Finally, Section F shows meter, services, meter-reading, and billing costs by schedule at the proposed rate-of-return.

The Excel model used to calculate the base case cost of service and supporting schedules have been included in its entirety electronically and a hard copy is 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. What are the key elements that define the cost of service methodology?

A. Consistent with the allocation methodologies defined within WAC 480-85-060 underground storage costs classified as balancing are allocated to all customers based on winter sales. All remaining costs are allocated to sales customers based on average winter sales that exceed average summer sales. Natural gas main investment is allocated based on peak demand and annual throughput, respectively. Other system facilities that serve all customers are classified by the peak and average ratio that reflects the system load factor, then allocated by peak demand and throughput, respectively. Meter installation and services investment is allocated by number of customers weighted by the relative installed cost of those items. General plant not specifically defined within rule is allocated based on the Company's blended four-part factor allocator (four-factor), discussed below. Administrative & general expenses are segregated into labor-related, plant-related, revenue-related, and "other". The costs are then allocated by factors associated with labor, plant in service, or revenue, respectively. The "other" A&G amounts are allocated based on the Company's four-factor.

Q. Please describe how investment in distribution mains is classified and allocated under the Company's proposed main allocation.

A. The investment in distribution main is classified as a demand-related cost, however, it is not allocated solely on peak demand. In accordance with WAC 480-85-060, the Company uses the system load factor for allocating this portion of its demand-related costs. This method allocates demand-related costs based on a combination of peak demand and average demand. Average demand is essentially another term for average throughput.

The Company used the system load factor to determine how much of the demand-related costs would be allocated based on annual throughput and how much would be allocated based on design day peak demand[4]. A system load factor was calculated based on throughput and peak demand. The load factor is the ratio of average load to peak load, and when multiplied by the plant investment, provides an estimate of the costs that can be attributed to average use rather than peak use.

The resulting load factor was used to divide the demand-related costs into peak demand and average demand for purposes of allocating the costs to the rate schedules, with the demand-related costs being allocated 40.4 percent on average demand and 59.6 percent on peak demand. The load factor provides a reasonable basis for determining what portion of the costs should be allocated based on average demand.

Q. Please describe how Customer Relations Distribution Costs are Classified.

A. Customer service, customer information and sales expenses are the core of the customer relations functional unit which is included with the distribution cost category. For the most part, these costs are classified as customer-related. The only exception is uncollectible accounts expense, which is considered separately as a revenue conversion item.

Q. How has the Company allocated the general plant costs, Intangible Plant

[4] Peak demand is defined as the actual five-day peak demand from the test year.

Costs and other A&G expenses (common costs)?

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. The remainder of general plant, intangible plant and other A&G expenses are considered common costs and are allocated based on the Company's four-factor. 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. Did the Company prepare an analysis of Intangible Plant balances while preparing this Cost of Service Study?

A. Yes. Account 303.120 software costs are associated with the meter data management system (MDM) and advanced metering infrastructure (AMI) project. 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 natural gas cost of service studies.

Results

Q. What are the results of the Company's natural gas cost of service study?

A. The cost of service study indicates that General Service Schedules 101/102 (serving mostly residential customers) and Transportation Schedule 146 are providing less than the overall rate of return (unity), and Large General and Interruptible Schedules (111/112/116, 131/132) are providing more than unity. The following table shows the rate of return, the relative return ratio and the parity ratio at present rates for each rate schedule.

Table No. 4 - Base Case Results

Rate Schedule	Rate of Return	Return Ratio	Parity Ratio
General Service Schedule 101/102	4.67%	0.82	0.94
Large General Service Schedules 111/112	12.67%	2.22	1.49
Interruptible Sales Service Schedule 132	9.22%	1.62	1.24
Transportation Service Schedule 146	2.33%	0.41	0.73
Total Washington Natural Gas System	5.71%	1.00	1.00

The summary results of the study were used for consideration in the development of the proposed rates.

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

A. Yes, it does.