Exhibit No. ___(JDM-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UG-16______

DIRECT TESTIMONY OF

JOSEPH D. MILLER

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Joseph D. Miller. My business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Senior Regulatory Analyst in the State and Federal Regulation Department.

Q. Would you briefly describe your responsibilities?

A. Yes. I am responsible for preparing and maintaining the regulatory natural gas cost of service models for the Company. I also provide support in the preparation of revenue analysis, rate spread and rate design, and miscellaneous other duties as required.

Q. Please describe your educational background and professional experience.

A. I am a 1999 graduate of Portland State University with a Bachelors degree in Business Administration, majoring in Accounting. In 2005 I graduated from Gonzaga University with a Masters degree in Business Administration. I joined the Company in March 2008 after spending eight years in both the public and private accounting sector. I started with Avista as a Natural Gas Accounting Analyst in the Company's Resource Accounting Department. In January 2009, I joined the State and Federal Regulation Department as a Regulatory Analyst. My primary responsibility was coordinating discovery for the Company's general rate case filings. In my current role, as a Senior Regulatory Analyst, I am responsible for the preparation of the Company's natural gas cost of service studies and revenue adjustments in all jurisdictions.

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

A. My testimony and exhibits will cover the Company's natural gas revenue normalization adjustments and 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 Exhibit No.___ (JDM-2) which includes a narrative of the natural gas cost of service study process, and Exhibit No.___ (JDM-3), the natural gas cost of service study summary results.

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

A. Yes they were.

Q. By way of summary what do your cost of service study results show?

A. The cost of service study indicates that General Service Schedule 101 (serves most residential customers) and Transportation Schedule (146) are providing less than the overall rate of return (unity), and Large General, High Load Factor Large General, and Interruptible service schedules (111/112, 121/122 and 131/132) are providing more than unity. The following table shows the rate of return and the relative return ratio at present rates for each rate schedule:

<u>Table No.1:</u>

Base Case Results

Rate Schedule	Rate of Return	Return Ratio
General Service Schedule 101	5.66%	0.84
Large General Service Schedules 111/112	12.08%	1.80
Ex. Lg. General Service Schedules 121/122	11.45%	1.70
Interruptible Sales Service Schedules 131/132	9.23%	1.37
Transportation Service Schedule 146	5.54%	0.82
Total Washington Natural Gas System	6.73%	1.00

II. NATURAL GAS REVENUE NORMALIZATION

Q. Would you please describe the natural gas revenue normalization adjustment included in Company witness Ms. Andrew's Attrition Study?

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

1 – The Commission Basis Results of Operations in Column [A] of Exhibit No.___(EMA-3), page 4, includes a Commission Basis weather normalization adjustment. Revenues and natural gas costs for this adjustment are based on rates that were in effect during the October 2014 through September 2015 test period, and the adjustment adjusts therm sales and revenues to reflect normal weather conditions.

2 – In addition to the weather normalization adjustment, the Commission Basis Results of Operations in Column [A] of Exhibit No.___(EMA-3), page 4, also includes an Eliminate Adder Schedule adjustment which removes the impact of the adder schedule revenues and related expenses during the October 2014 through September 2015 test period.

3 – The Pro Forma Revenue Normalization Adjustment in column [C] of Exhibit No.___(EMA-4), page 4, adjusts October 2014 through September 2015 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 2016, as if the January 11, 2016 base tariff rates were effective for the full 12-months of the test year. The Pro Forma Revenue Normalization Adjustment removes all revenue and expenses associated with the natural gas purchased to serve sales customers and pipeline transportation to get it to our system (Schedule 150 – Purchased Gas Adjustment Costs).

Weather Normalization:

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

Q. In the discussion of electric weather normalization sponsored by Ms. Knox, she indicated that the adjustment utilized sensitivity factors from the ten year period January 2005 through December 2014. Is this true for natural gas as well?

A. Yes, the natural gas weather adjustment utilized updated weather sensitivity factors for the same ten-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 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 1986 through 2015.

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 No. UG-150205. This methodology has been used in every case since it was introduced in Docket No. UG-070805.

Q. What was the impact of natural gas weather normalization on the twelve months ended September 2015 test year?

A. Weather was warmer than normal during the October 2014 through June 2015 period. The adjustment to normal required the addition of 1,062 heating degree-days from October through December and January through June.[1] The adjustment to sales volumes was an addition of 21,269,632 therms which is approximately 9.3 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 $18,053,000, which after the offsetting reduction to purchased gas expense of $10,600,000 resulted in an increase to distribution margin of $7,453,000. The combined effect of netting the increase to distribution margin against the decoupling revenue offset of $5,069,000, resulted in a net margin weather adjustment of $2,384,000.[2] After an offsetting reduction for revenue related expenses and taxes, the weather normalization adjustment produced an increase to net operating income of $1,154,000.

<u>Eliminate Adder Schedules:</u>

Q. Moving on to the <u>second revenue normalizing</u> adjustment in the Attrition Study, what is the purpose of the Eliminate Adder Schedule adjustment?

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:

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[1] 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.

[2] The Decoupling Mechanism went into effect January 1, 2015, and was therefore in effect during the months of January through September of the Company's test year.

Schedule 191 Demand Side Management Rate Adjustment, Schedule 192 Low Income Rate Assistance Program Rate Adjustment, and Schedule 155 Gas Rate Adjustment amortization surcharge or rebate. This adjustment also identifies and consolidates all of 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 <u>third revenue normalizing</u> adjustment in the Attrition Study. What is the purpose of 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 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 October 2014 through September 2015 test period, as if the base tariff rates effective January 11, 2016 (Docket No. UG-150205) had been in effect for the full twelve months of the 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 operating income before federal income taxes by $12,311,000, which after income taxes increases Washington net operating income $8,002,000, as shown in column [C] on pages 4 and 5 of Exhibit No.___(EMA-3).

Q. Are the same normalized restated distribution revenues included in Company witness Ms. Smith's Pro Forma and Cross Check studies shown in Exhibit No.___(JSS-3)?

A. Yes, the Weather Normalization adjustment is shown as adjustment 2.10 and the Eliminate Adder Schedule adjustment is shown as adjustment 2.11 on page 8 of Exhibit No.__ (JSS-3). The Pro Forma Revenue Normalization adjustment is shown as adjustment 3.05 on page 9 of Exhibit No.__ (JSS-3).

III. NATURAL GAS COST OF SERVICE

Q. Please identify the natural gas cost studies presented to this Commission in the last five years as required by WAC 480-07-510 (6).

A. Natural gas cost of service studies were filed with this Commission in Docket Nos. UG-150205, UG-140189, UG-120437, UG-110877, and UG-100468.

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 year load and facilities requirements, resulting in an evaluation of the cost of the service provided to each group. The rate of return by customer group indicates whether the revenue provided by the customers in each group recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers. Exhibit No.___(JDM-2) explains the basic concepts involved in performing a natural gas cost of service study. It also details the specific methodology and assumptions utilized in the Company's Base Case cost of service study.

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

A. The cost of service study provided by the Company as Exhibit No.___(JDM-3) is based on the attrition-adjusted revenue requirement for the 2017 rate period as determined by Ms. Andrews. The twelve months ended September 2015 test year Pro Forma and Cross Check studies presented by Ms. Smith in Exhibit No.___(JSS-3), including total expenses and rate base, were adjusted and reconciled with the Attrition Study in order to provide the detailed cost basis for the cost of service study in this case.

Q. Would you please explain the cost of service study presented in Exhibit No.___(JDM-3)?

A. Yes. Exhibit No. ___(JDM-3) is composed of a series of summaries of the cost of service study results. Page 1 shows the results of the study by FERC account category. The rate of return and the ratio of each schedule's return to the overall return are shown on lines 38 and 39. This summary is provided to Company witness Mr. Ehrbar for his consideration regarding rate spread and rate design. The results will be presented later in my testimony. Additional summaries show the costs organized by functional category (page 2) and classification (page 3), including margin and unit cost analysis at current and proposed rates. Finally, page 4 is a summary identifying specific customer related costs embedded in the study.

The Excel model used to calculate the base case cost of service and supporting schedules have been included in its entirety both electronically and hard copy in the workpapers accompanying this case.

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 applied to the study presented in Docket No. UG-150205.

Q. What are the key elements that define the cost of service methodology?

A. Underground storage costs are segregated proportionately into commodity storage benefits for sales customers and load balancing benefits for all customers. Natural gas main investment is allocated by coincident peak demand and throughput, respectively. The throughput portion of the main investment allocation has been segregated into small, medium and large mains, with large usage customers (Schedules 131/132 & 146) receiving zero allocation of small mains and a 33% of allocation of medium mains. Other system facilities that serve all customers are classified by the peak and average ratio that reflects the system load factor, then allocated by coincident peak demand and throughput, respectively.

Meter installation and services investment is allocated by number of customers weighted by the relative current cost of those items. General plant is allocated based on the Company's blended 4-part factor allocator (4-factor). 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 4-factor. A detailed description of the methodology is included in Exhibit No.___(JDM-2).

Distribution Main Cost Allocation

Q. Is the Company's approach to the allocation of distribution mains consistent with what was proposed in the Company's last general rate case (UG-150205)?

A. Yes. There have been varying points of view as to the proper allocation of distribution mains as illustrated in the testimony sponsored by several parties in the Company's prior general rate cases (UG-140189 & UG-120437). The Company's approach produces an allocation method that we believe 1) is consistent with cost of service principles, 2) acknowledges past Commission decisions, 3) is consistent with Avista's distribution system, and 4) is both fair and balanced to all customer classes.

Q. Please briefly summarize the distribution main allocation methodology the Company is proposing in this proceeding?

A. The Company is continuing to apply the peak and average ratio to classify distribution main investment into both demand and commodity related costs. The portion of main investment classified as demand related is allocated to <u>all</u> rate schedules on the basis of each schedule's contribution to system peak demand. The demand related allocation does not attempt to separate distribution main based on pipe size.

The portion of distribution main investment classified as commodity related has been separated main into three groups (small, medium & large) instead of two. Large main (4 inches and greater) is allocated to all rate schedules based on annual weather normalized throughput. Small main (less than 2 inches) is allocated to all rate schedules with the exception of Schedules 131/132 & 146 based on weather normalized throughput. Medium main (2 and 3 inches) is allocated 33 percent to all rate schedules and 67 percent to all rate schedules except Schedules 131/132 & 146 based on weather normalized throughput.

Q. Please summarize the major concern the Company is addressing by its proposed distribution main allocation?

A. The major concern the Company is addressing is that, under the prior approach, not enough costs were being allocated to larger usage customers based on the benefits they receive from being connected to the entire natural gas distribution system. The allocation the Company used in its prior general rate case filings (prior to UG-150205) separated distribution main investment into both small (less than 4 inches) and large (4 inches and greater) main. Large usage customers that took service from large mains did not receive an allocation of small mains. Large usage customers that took service from small mains had their associated throughput and coincident peak demand assigned to the small main allocation factors, and received a relatively small allocation of small main costs. Finally, the Company individually analyzed all large interruptible and transportation customers (Schedules 131/132 and 146) to determine what size of pipe each customer directly took service from and any portion of pipe that was directly assignable to a particular customer.

Under the prior approach, any large customer who was connected to large main did not receive any allocation of small main. By excluding these customers from the small main allocation altogether, the prior methodology ignored any benefits that large customers receive from being connected to a broader distribution system which is heavily dependent on small main.

Q. Please describe the benefit all customers receive from being connected to Avista's natural gas distribution main.

A. Avista's natural gas distribution system is a network of pipes that includes parallel and interconnected lines from which different pipes are used to move gas from one point to another. The Company generally chooses to use 2 inch diameter pipes to serve smaller customers and 4 or 6 inch diameter pipes to serve larger customers. However, all sizes of pipe create capacity on the system. If there were less 2 inch diameter pipe, there would need to be larger-sized pipe on the system, or less capacity would be available to serve all customers, both large and small. The existence of smaller pipe makes capacity available for everyone.

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. Following a long-standing practice, the Company continues to use the peak and average method for allocating this portion of its demand-related costs. This method allocates demand costs based on a combination of peak demand and average demand. Average demand is essentially another term for average throughput.

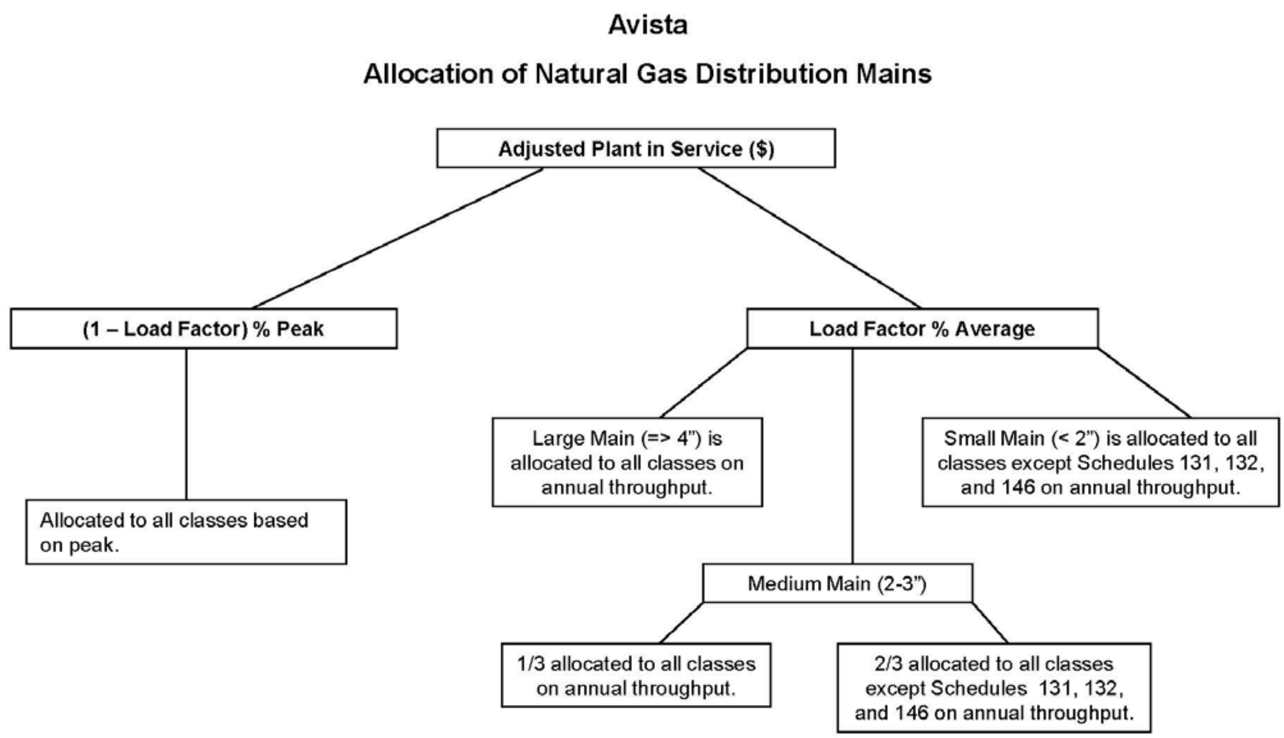
The Company used the system load factor to determine how much of the demand-related costs would be allocated based on average demand and how much would be allocated based on peak demand. A system load factor was calculated based on weather-normalized throughput and peak demand. The load factor is the 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 39.8 percent on average demand and 60.2 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.

This peak and average approach to allocation of demand costs reflects a balance between the way the system is designed (to meet peak demand) and the way it is utilized on an annual basis (throughput based on gas usage that occurs during all conditions, not only peak conditions).

Q. Please describe how the peak and average method of cost allocation was used to allocate the cost of distribution mains to the rate schedules.

A. Illustration No. 1 provides a flow diagram of the steps referenced below.



demand using the system load factor described above. This resulted in $80.6 million (39.8 percent) of plant allocated based on average demand and $122.1 million (60.2 percent) allocated based on peak demand.

Second, the $122.1 million, or 60.2 percent, to be allocated based on peak demand was allocated to all rate schedules based on their estimated contributions to the peak demand.

Third, the $80.6 million, or 39.8 percent, to be allocated based on average demand was split into three groups: 1) large main (greater than or equal to four inches in diameter), 2) medium main (two and three inches in diameter), and 3) small main (less than two inches in diameter). Large main is allocated to all rate schedules based on annual weather normalized throughput. Small main is allocated to all rate schedules with the exception of Schedules 131/132 & 146 based on weather normalized throughput. Medium main is allocated 33 percent to all rate schedules and 67 percent to all rate schedules except Schedules 131/132 & 146 based on weather normalized throughput.

Q. Why were small mains (less than two inches) not allocated to all rate schedules?

A. The smallest mains are generally located in isolated parts of the Company's distribution system and are unlikely to provide benefits to the large customer loads served on Schedules 131/132 and 146.

Q. For medium mains (two & three inches), why were they split into two groups?

A. Historically, there have been two opposing points of view regarding the allocation of mains. One view is founded on a belief that customers only benefit from pipe through which gas molecules flow, or might flow, to reach their locations, and thus should only be allocated a share of the cost of those specific pipe sizes. The other view would argue that the gas distribution network provides an integrated system which benefits all customers, regardless of the customer's location on the system and regardless of which specific diameter of pipe they are served from. The Company believes that larger customers do benefit, at some level, from the medium main on the gas distribution network. While they may not benefit from all of the medium main, we believe it is not reasonable to assert that medium main provides no benefit to large customers. Therefore, medium main has been allocated 33 percent to all rate schedules, and 67 percent to all rate schedules except Schedules 131/132 & 146, based on weather normalized throughput.

Q. Why did the Company choose the one-third, two-thirds split, with one-third of medium main being allocated to all rate schedules and two-thirds to all rate schedules except 131/132 & 146?

A. The Company considered the historical treatment of Schedule 131/132 and 146 customers and the benefits they have received associated with being part of the entire gas distribution system. Historically, Schedule's 131/132 & 146 customers had some assignment of costs related to small and medium main, but that assignment was minimal. A one-third allocation for Schedule 131/132 & 146 customers provides a meaningful allocation of medium main, and is consistent with the allocation both Puget Sound Energy[3] and Commission Staff[4] have proposed in recent proceedings.

Q. Please summarize the benefits of the Company's proposed approach to allocating distribution mains.

A. There are four benefits to the Company's approach. First, this method recognizes that all customers benefit from the gas distribution system of medium to large mains as a whole, and not solely from the actual main through which gas flows to reach the individual customer. Second, by exempting certain large rate schedules from the cost of the smallest diameter mains (less than two inches), this approach acknowledges that the smallest main is unlikely to benefit large Schedule 131/132 & 146 customers. Third, the Company's approach recognizes that the benefits of medium diameter mains to large interruptible and transportation customers are less than the benefits medium diameter mains provide to other

[3] Dockets UG-090705, UG-101644, and UG-111049, see Direct Testimony of Janet K. Phelps
[4] Dockets UG-120437 and UG-140189, see Direct Testimony of Christopher T. Mickelson

customers, however the benefits, and therefore assigned cost, should be higher than traditionally assigned. Finally, the Company's methodology is relatively transparent and easy to understand.

Q. Has the Company's approach to the allocation of distribution mains been proposed by other parties in previous general rate case filings?

A. Yes. A similar approach for allocating distribution mains was proposed by Commission Staff in two prior general rate cases (Docket Nos. UG-140189 and UG-120437). In addition, Puget Sound Energy (Docket Nos. UG-111049, UG-101644, and UG-090705) has also proposed a similar methodology in several of its most recent general rate case filings.

General Plant Costs and Other A&G Expenses (Common Costs)

Q. How has the Company allocated the general plant costs and other A&G expenses (common costs)?

A. The Company has allocated both general plant and other A&G expenses, which are functionalized as common costs, based on the Company's blended 4-part factor allocator (4-factor). This allocation factor is used on all common plant and other A&G expenses and is the cost of service equivalent of the 4-factor allocator used in the Company's results of operations reporting. The 4-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 4-factor?

A. The 4-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 4-factor allocator?

A. There are two primary benefits of the 4-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. Has the 4-factor allocation been proposed by other parties in the Company's previous general rate case filings?

A. Yes. Commission Staff proposed this same allocation methodology in a prior Avista general rate case (UG-140189).

IV. RESULTS

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

A. The Base Case cost of service study presented in this filing is a fair representation of the costs to serve each customer group. The study indicates that the General Service Schedule 101 (serves most residential customers) and Transportation

Schedule (146) are providing less than the overall rate of return (unity), and Large General, High Load Factor Large General, and Interruptible service schedules (111/112, 121/122 and 131/132) are providing more than unity. Table No. 2 shows the rate of return and the relative return ratio at present rates for each rate schedule.

Table No.2:

Base Case Results

Rate Schedule	Rate of Return	Return Ratio
General Service Schedule 101	5.66%	0.84
Large General Service Schedules 111/112	12.08%	1.80
Ex. Lg. General Service Schedules 121/122	11.45%	1.70
Interruptible Sales Service Schedules 131/132	9.23%	1.37
Transportation Service Schedule 146	5.54%	0.82
Total Washington Natural Gas System	6.73%	1.00

The summary results of the study were provided to Mr. Ehrbar for consideration in the development of the proposed rates.

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

A. Yes.