Exh. JDM-1T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-19_____

DOCKET NO. UG-19_____

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 and my business address is 1411 East Mission Avenue, Spokane, Washington. I am presently assigned to the Regulatory Affairs Department as Manager of Pricing and Tariffs.

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

A. Yes. I am a 1999 graduate of Portland State University with a Bachelor's degree in Business Administration, majoring in Accounting. In 2005, I graduated from Gonzaga University with a Master's 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 Manager of Pricing and Tariffs, I am responsible for the Company's electric and natural gas rate design, natural gas cost of service studies in all jurisdictions, and tariff administration, among other things.

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

A. My testimony will cover the spread of the proposed annual electric <u>base</u> revenue increase in Year 1 of the Two-Year Rate Plan of $45,775,000, or 9.1%, among the Company's electric general service schedules. On a total <u>billed</u> revenue basis the increase is 8.8%.

With regard to natural gas service, I will describe the spread of the proposed annual <u>base</u>

revenue increase in Year 1 of the Two-Year Rate Plan of $12,935,000, or 13.8%, among the Company's natural gas service schedules. On a billed basis, which incorporates the cost of natural gas, demand-side management funding, etc., the proposed increase is 10.1%.

My testimony will also describe the changes to the rates within the Company's electric and natural gas service schedules, and the proposed rate spread, rate design, and implementation related to the Company's proposed Two-Year Rate Plan.

In addition, my testimony presents the natural gas cost of service study and revenue normalization adjustment prepared for this filing. Company witness Knox will testify regarding the electric cost of service study and the electric revenue normalization adjustment.

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

A. Yes. I am sponsoring Exh. JDM-2, Exh. JDM-3, and Exh. JDM-4 related to the proposed electric increases, Exh. JDM-5, Exh. JDM-6, and Exh. JDM-7 related to the proposed natural gas increases, and Exh. JDM-8 and Exh. JDM-9 related to the natural gas cost of service study. These exhibits were prepared under my supervision. A table of contents for my testimony is as follows:

II. PROPOSED ELECTRIC REVENUE CHANGES

Summary of Electric Rate Schedules and Tariffs

Q. Would you please explain what is contained in Exh. JDM-2?

A. Yes. Exh. JDM-2 contains a copy of the Company's present electric tariffs/service schedules.

Q. Would you please describe what is contained in **Exh. JDM-3**?

A. Yes. Exh. JDM-3 contains the proposed electric tariff sheets incorporating the proposed changes included in this filing.

Q. Please describe what is contained in Exh. JDM-4.

A. Exh. JDM-4 contains information regarding the proposed spread of the electric revenue increase among the service schedules and the proposed changes to the rates within the schedules for the Two-Year Rate Plan. Page 1 shows the proposed general revenue and percentage increase by rate schedule compared to the present revenue under base tariff and billing rates. Page 2 shows the rates of return and the relative rates of return for each of the schedules before and after application of the proposed general increase. Page 3 shows the present rates under each of the rate schedules, the proposed changes to the rates within the schedules, and the proposed rates after application of the changes. Page 4 shows the estimated increases in billed revenues, and resulting rate spread, related to year 2 of the proposed Two-Year Rate Plan. Page 5 provides the proposed rates for year 2 of the Two-Year Rate Plan. These pages will be referred to later in my testimony.

Q. Would you please describe the Company's present rate schedules and the types of electric service offered under each?

A. Yes. The Company presently provides electric service under Residential Service Schedules 1 and 2, General Service Schedules 11 and 12, Large General Service Schedules 21 and 22, Extra Large General Service Schedule 25, and Pumping Service Schedules 31 and 32. Additionally, the Company provides Street Lighting Service under Schedules 41-46, and Area Lighting Service under Schedules 47-48. Schedule 2 exists for purposes of administering the Company's "Fixed-Income Senior & Disabled Residential Service" pilot program. The rates for this schedule are identical to the rates for Schedule 1, except for the rate discount. Schedules 12, 22, 32, and 48 exist for residential and farm service customers who qualify for the Residential Exchange Program operated by the Bonneville Power Administration. The rates for these schedules are identical to the rates for Schedules 11, 21, 31, and 47, respectively, except for the Residential Exchange rate credit.

Table No. 1 below shows the type and number of customers served in Washington (as of December 2018) under each of the service schedules:

Table No. 1 – Electric Customers by Service Schedule

Rate Schedule	No. of Customers
Residential Schedules 1/2	217,126
General Service Schedules 11/12	32,330
Large General Service Schedules 21/22	1,901
Extra Large General Service Schedule 25	23
Pumping Service Schedules 31/32	2,420

Proposed Year 1 Electric Rate Spread

Q. What is the proposed electric revenue increase, and how is the Company proposing to spread the increase by rate schedule?

A. The proposed electric increase is $45,775,000 or 9.1% over present base tariff rates in effect. The proposed general increase over present billing rates, including all other rate adjustments (such as DSM and Residential Exchange), is 8.8%. The proposed percentage increase by rate schedule is as follows:

Table No. 2 – Proposed % Electric Increase by Schedule (April 1, 2020)

Rate Schedule	Increase in Base Rates	Increase in Billing Rates
Residential Schedules 1/2	10.0%	9.8%
General Service Schedules 11/12	7.3%	7.0%
Large General Service Schedules 21/22	9.1%	8.7%
Extra Large General Service Schedule 25	9.1%	8.8%
Pumping Service Schedules 31/32	9.1%	8.7%
Street & Area Lights Schedules 41-48	0.0%	0.0%
Overall	**9.1%**	**8.8%**

This information is shown with more detail on Page 1 of Exh. JDM-4.

Q. What information did the Company use to develop the proposed spread of the overall increase to the various rate schedules?

A. The Company believes that the results of the cost of service study (sponsored by Company witness Ms. Knox) should be used as a guide to spread the general increase. The Company is also cognizant that most of the parties that participate in the Company's general rate cases are also involved in the on-going cost of service workshops stemming from the Company's 2016 general rate case. While it is important to see what, if any, changes to cost of service methodologies come from those proceedings, Avista believes that the results from a variety of cost studies will continue to show that two sets of schedules in particular, Residential Schedules 1/2 and General Service Schedules 11/12, are too far away from the overall rate of return (unity), and have been for some time.

In recent years, the rate of return provided by Residential Schedules 1/2 has been significantly less than the overall rate of return. This is true not only for cost of service studies conducted by Avista, but also from studies conducted by other parties. Table No. 3 below shows the relative rates of return (schedule rate of return divided by overall rate of return) for Schedules 1/2 from recent general rate cases:

Table No. 3 – Relative Rates of Return for Schedules 1/2

Avista Docket	Cost of Service Study Sponsor	Schedules 1/2 Relative Rate of Return
UE-120436	Avista	0.58
UE-120436	Staff	0.58
UE-120436	ICNU	0.46
UE-140188	Avista	0.65
UE-140188	Staff	0.54
UE-140188	ICNU	0.57
UE-150204	Avista	0.58
UE-160228	Avista	0.55
UE-160228	ICNU	0.46
UE-170485	Avista	0.56
	Average	**0.55**

Likewise, General Service Schedules 11/12 have provided relative rates of return that are significantly higher than the overall rate of return. This is true not only for cost of service studies conducted by Avista, but also from studies conducted by other parties. Table No. 4 below shows the relative rates of return for Schedules 11/12 from recent general rate cases:

Table No. 4 – Relative Rates of Return for Schedules 11/12

Avista Docket	Cost of Service Study Sponsor	Schedules 11/12 Relative Rate of Return
UE-120436	Avista	2.09
UE-120436	Staff	2.09
UE-120436	ICNU	2.21
UE-140188	Avista	1.92
UE-140188	Staff	1.66
UE-140188	ICNU	2.00
UE-150204	Avista	1.95
UE-160228	Avista	1.98
UE-160228	ICNU	2.02
UE-170485	Avista	2.03
	Average	**2.00**

Based on the analysis provided above, Avista is proposing that General Service Schedules 11/12 receive an increase that is 80% of the overall proposed base rate percentage increase, and that all other service schedules, with the exception of Residential Service Schedules 1/2 and Street and Area Lights Schedules 41-48 (discussed below), receive a base rate percentage increase equal to the overall proposed base rate percentage increase. The remaining revenue requirement would be spread to Residential Service Schedules 1/2 (resulting in an increase that is approximately 110 percent of the overall base rate percentage increase). Avista believes this proposed rate spread will help to make more meaningful progress towards unity for most schedules, including Schedules 1/2 and 11/12, even while the parties participate in the cost of service workshops.

Table No. 5 below shows the relative rates of return (schedule rate of return divided by overall rate of return) before and after application of the base rate increase:

<u>Table No. 5 - Present & Proposed Relative Rates of Return (Electric)</u>

Rate Schedule	Present Relative ROR	Proposed Relative ROR
Residential Schedules 1/2	0.43	0.59
General Service Schedules 11/12	2.24	1.88
Large General Service Schedules 21/22	1.55	1.41
Extra Large General Service Schedule 25	1.08	1.11
Pumping Service Schedules 31/32	0.85	0.87
Street & Area Lights Schedules	1.14	0.81
Overall	**1.00**	**1.00**

Q. What is the proposed electric revenue change for Street and Area Lights?

A. The Company is proposing to not allocate any of the revenue increase to Street and Area Light Schedules 41-48. In recent years the Company has heard from many of its customers in smaller communities in Avista's service territory that budgets are constrained and they are continually looking for ways to reduce costs. Since most communities regularly need to pass local tax levies to fund street-related expenses (including streetlights), eliminating or reducing streetlight expenses is one of the easiest ways for them to reduce costs and balance budgets. While this poses a challenge for local officials who want adequate lighting levels for public safety, it's an easy approach in reducing operating expenses. The strategy of eliminating street lights reduces revenue to Avista, which in turn increases the overall revenue need paid by all customers. This type of service can be seen as a more discretionary expenditure, and it is our goal to keep these customers connected to the system. For these reasons, Avista is proposing to not allocate any of the revenue increase to Street and Area Lights in an attempt to not further increase the burden many of these small communities have been experiencing in recent years.

Q. How much of the present base rate electric revenue is associated with Street and Area Lights?

A. Approximately $6.4 million, or only 1.3%, of Avista's present base rate revenue is derived from the Company's Street and Area Light customers. A uniform percentage of base rate revenue increase to the Street and Area Light schedules would have approximated $0.59 million, or 9.1%. Assigning this increase to Residential customers increases their percentage change by 0.27%. The Company does not believe the relatively small dollar increase that could have been allocated to Street and Area Light customers will provide a burden to the Residential customers who are being allocated a slightly larger increase (and whom are well below cost of service even after application of the revenue changes). This approach is also supported by the cost of service study prepared by Ms. Knox which shows the Residential schedule at 0.43 on a relative rate of return basis. Accordingly, this proposal is justified on that basis alone, with Street and Area Lights providing a much greater return than the Residential customers.

<u>Proposed Year 1 Rate Design</u>

Q. Where in your Exhibits do you show a comparison of the present and proposed rates within each of the Company's electric service schedules?

A. Page 3 of Exh. JDM-4 shows a comparison of the present and proposed rates within each of the schedules, which I will describe below. Column (a) shows the rate/billing components under each of the schedules, column (b) shows the base tariff rates within each of the schedules, column (c) shows the present rate adjustments applicable under each schedule, and column (d) shows the present billing rates. Column (e) shows the proposed general rate increase to the rate components within each of the schedules. Finally, column (f) shows the proposed billing rates and column (g) shows the proposed base tariff rates.

Q. Is the Company proposing any changes to the existing rate structures within its rate schedules?

A. No, it is not.

Q. Turning to Residential Service Schedules 1/2, would you please describe the present rate structure under these schedules?

A. Yes. Residential Schedules 1/2 have a present customer or basic charge of $9.00 per month and three energy rate blocks: 0-800 kWhs, 801-1,500 kWhs and over 1,500 kWhs. The present base tariff rate for the first 800 kWhs per month is 7.533 cents per kWh, 8.765 cents per kWh for the next 700 kWhs, and 10.276 cents for all kWhs over 1,500.

Q. How does the Company propose to spread the proposed revenue increase of $21,656,000 to Schedules 1/2?

A. The Company is not proposing to increase the basic charge of $9.00 per month, and is proposing to apply an equal percentage increase to the three energy blocks.

Q. Why is the Company not proposing to increase the monthly customer charge from $9.00 per month?

A. As discussed further by Company witness Mr. Ehrbar, Avista's Decoupling Mechanisms provide the Company with a significant amount of fixed cost recovery thus lessoning the Company's exposure to fixed cost revenue volatility that would otherwise occur absent Decoupling. Because of the fixed cost recovery provided by the Decoupling Mechanism, the Company is not proposing to increase the basic charge in this proceeding.

Q. For April 1, 2020, what is the proposed monthly bill increase for a residential electric customer with average consumption?

A. The proposed monthly bill increase for a residential customer using an average of 918 kWhs per month is $7.93 per month, or a 9.8% increase in their electric bill. The present bill for 918 kWhs is $81.21 compared to the proposed level of $89.14, including all rate adjustments.

Q. Turning to General Service Schedules 11/12, would you please describe the present rate structure and rates under these schedules?

A. Yes. The present rate structure under these schedules includes a monthly customer charge of $20.00, an energy rate of 11.349 cents per kWh for all usage up to 3,650 kWhs per month, and an energy rate of 8.341 cents per kWh for usage over 3,650 kWhs per month. There is also a demand charge of $6.50 per kW for all demand in excess of 20 kW per month. There is no charge for the first 20 kW of demand.

Q. How is the Company proposing to apply the proposed general revenue increase of $5,475,000 to the rates under Schedules 11/12?

A. For similar reasons discussed previously regarding Schedules 1/2, the Company is <u>not</u> proposing an increase to the customer charge of $20.00 per month. In addition, the Company is proposing that the demand charge (over 20 kW) be increased $0.50 per kW, from $6.50 to $7.00. The remaining revenue increase for the schedules is proposed to be recovered through a uniform percentage increase applied to the two (block) energy rates. The increase in the first block rate is 0.925 cents per kWh, and 0.680 cents per kWh for the second block rate. Finally, the Company is proposing to increase the minimum charge for single phase service from $15.00 to $20.00 per month, and three phase service from $25.35 to $27.35 per month.

Q. Why is the Company proposing a $0.50 increase to the demand charge?

A. The system allocated demand cost from the cost of service study is $22.36 per kilowatt (kW) month.[1] The Company's present monthly demand charge is $6.50/kW or kVA. While the exact level of costs classified as demand-related can be debated, the proposed demand charges will continue to be well below demand-related costs.

In addition, the Company's transmission and distribution system is constructed to meet the collective peak demand of its customers. Further, the Company must have adequate resources available to meet peak demand. If customers reduce their peak demand, it will reduce the need for additional investment in these facilities and resources. Customers need to receive the proper price signal to encourage a reduction in their peak demand, i.e., higher demand charges.

Q. Turning to Large General Service Schedules 21/22, would you please describe the present rate structure under those schedules and how the Company is proposing to apply the increase of $11,460,000 to the rates within the schedules?

A. Yes. Large General Service Schedules 21/22 consists of a minimum monthly charge of $500.00 for the first 50 kW or less, a demand charge of $6.50 per kW for monthly demand in excess of 50 kW, and two energy block rates: 7.189 cents per kWh for the first 250,000 kWhs per month, and 6.430 cents per kWh for all usage in excess of 250,000 kWhs.

The Company is proposing that the present minimum demand charge (for the first 50 kW or less) be increased by $50.00, from $500.00 to $550.00 per month. The demand charge for kW over 50 per month would be increased by $0.50 per kW, from $6.50 to $7.00, for the reasons provided previously in my testimony. The remaining revenue increase for the schedules

[1] Knox Exh. TLK-3, at 3, ln. 28.

is proposed to be recovered through a uniform percentage increase applied to the two energy block rates. The proposed increase for the first 250,000 kWhs used per month is 0.667 cents per kWh, and an increase of 0.594 cents per kWh for usage over 250,000 kWhs per month.

Q. Turning to Extra Large General Service Schedule 25, would you please describe the present rate structure under that schedule and how the Company is proposing to apply the increase of $6,086,000 to the rates within the schedule?

A. Yes. Extra Large General Service Schedule 25 consists of a minimum monthly charge of $24,000 for the first 3,000 kVa or less, a demand charge of $6.50 per kVa for monthly demand in excess of 3,000 kVa, and three energy block rates: 5.505 cents per kWh for the first 500,000 kWhs per month, 4.953 cents per kWh for the next 5.5 million kWhs, and 4.235 cents per kWh for all usage in excess of 6 million kWhs.

The Company is proposing that the present minimum demand charge under the schedule should increase by $2,500 per month, to $26,500 per month. The demand charge for kVa over 3,000 per month is proposed to be increased by $0.50 per kVa, from $6.50 to $7.00. The remaining revenue increase for the schedule is proposed to be recovered through a uniform percentage increase applied to the three energy block rates. The proposed energy rate increase for the first 500,000 kWhs used per month is 0.487 cents per kWh, 0.439 cents per kWh for the next 5.5 million, and 0.375 cents per kWh for all usage over 6 million kWhs per month.

Q. Turning to Pumping Schedules 31/32, would you please describe the present rate structure under that schedule?

A. Yes. Pumping Schedules 31/32 consist of a monthly basic charge of $20.00 per month, and three energy block rates: 9.712 cents per kWh for the first 85 kWh per kW of demand, 9.712 cents per kWh for the next 80 kWh per kW of demand (but not more than 3,000 kWhs), and 6.936 cents per kWh for all additional usage.

Q. What changes are you proposing to the rates under Pumping Schedules 31/32 to recover the general revenue increase of $1,098,000?

A. For similar reasons discussed previously regarding Schedules 1/2, the Company is <u>not</u> proposing an increase to the customer charge of $20.00 per month. The revenue increase is proposed to be spread on a uniform percentage increase to the three energy rate blocks under the schedules. The proposed increase in the first and second block rate is 0.931 cents per kWh, and the increase in the third block rate is 0.666 cents per kWh.

Q. Turning to Street and Area Light Schedules 41-48, would you please describe the present rate structure under that schedule?

A. Yes. Street and Area Light Schedules consist of monthly flat rates, based on the type of light, the wattage of the light, and the type of structure the light is attached to.

Q. Is the Company proposing to increase the general revenue to Street and Area Light rates contained in schedules (Schedules 41-48)?

A. As previously discussed, the Company is not proposing to increase the base tariff rates for Street and Area Light Schedules 41-48.

Q. Is the Company proposing any other changes to its Street and Area Light schedules?

A. Yes. The Company is proposing to add several banded Light Emitting Diode (LED) rates under its Schedule 46 rate schedule. Schedule 46 is an energy only lighting option applicable to customer owned street lights. Presently the Company has few LED lighting options under rate Schedule 46. Through discussions with Avista's key Account Executive's it has come to the Company attention that at least one large customer is contemplating a large scale change-over from Sodium Vapor lights to LED's. This customer has inquired about the need for several different LED light codes based on the various wattage requirements. While the Company could facilitate this request by developing several individual rates at the time the lights are converted by utilizing the Schedule 46 "Custom Light Calculation" described within the present tariff, the Company believes it will be administratively more efficient to create banded light codes, in 10 watt increments, that would encompass any new LED light wattage customers may choose to install.[2] The Company has utilized the Custom Light Calculation within the tariff to calculate the applicable energy charges. Because these new LED banded rates will encompass all future LED lighting rate requests, the Company is proposing to discontinue the Custom Light Calculation within the Schedule 46 tariff.

Q. Is the Company proposing any other administrative changes to its Street and Area Light schedules?

A. Yes. The Company has made some minor housekeeping type changes to clean up the Street and Area Light tariffs which mostly remove lighting options that are no longer being used by our customers.

Q. Turning now to decoupling, how will new baseline information be incorporated into the electric Decoupling Mechanism?

A. As in the prior general rate case, the Company would, as a part of its Compliance Filing, submit the final baseline values for its electric Decoupling Mechanism prior to new rates going into effect as a result of this general rate case.

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[2] The Company created 25 watt bands for the largest LED bands from 200 – 225 and 226 – 250 in an effort to minimize the number of new codes for wattage equivalents that are unlikely to be used by any customers.

III. PROPOSED NATURAL GAS REVENUE CHANGES

Summary of Natural Gas Rate Schedules and Tariffs

Q. Would you please explain what is contained in Exh. JDM-5?

A. Yes. Exh. JDM-5 contains a copy of the Company's present natural gas tariffs presently on file with the Commission.

Q. Please describe what is contained in Exh. JDM-6?

A. Exh. JDM-6 contains the proposed natural gas tariff sheets incorporating the proposed changes included in this filing.

Q. Please explain what is contained in Exh. JDM-7?

A. Exh. JDM-7 contains information regarding the proposed spread of the natural gas revenue increase among the service schedules and the proposed changes to the rates within the schedules. Page 1 shows the proposed revenue and percentage increase by rate schedule. Page 2 shows the rates of return and the relative rates of return for each of the schedules before and after the proposed increases. Page 3 shows the present rates under each of the rate schedules, the proposed changes to the rates within the schedules, and the proposed rates after application of the changes. Page 4 shows the estimated increases in billed revenues, and resulting rate spread, related to year 2 of the Company's Rate Plan. Page 5 provides the proposed rates for year 2 of the Two-Year Rate Plan. These pages will be referred to later in my testimony.

Q. Would you please review the Company's present rate schedules and the types of natural gas service offered under each?

A. Yes. The Company's present Schedules 101, 111 and 121 offer firm sales service. Schedule 101 generally applies to residential and small commercial customers who use less than 200 therms/month. Schedule 111 is generally for customers who consistently use over 200 therms/month, and Schedule 121 is generally for customers who use over 10,000 therms/month and have a high annual load factor. Schedule 131 provides interruptible sales service to customers whose annual requirements exceed 250,000 therms. Schedule 146 provides transportation/distribution service for customer-purchased natural gas for customers whose annual requirements exceed 250,000 therms. Schedule 148 is a banded-rate transportation tariff that allows for a negotiated service rate with large customers that have an economic alternative to taking natural gas distribution service from the Company.

Q. Would you please explain which customers are eligible for service under Schedules 102, 112, 122 and 132?

A. Yes. Schedule 102 exists for purposes of administering the Company's "Fixed-Income Senior & Disabled Residential Service" pilot program. The rates under this schedule are the same as those under Schedule 101, except for the rate discount.

Schedules 112, 122 and 132 are in place to provide service to customers, who, at one time, were provided natural gas service under Transportation Service Schedule 146. The rates under these schedules are the same as those under Schedules 111, 121 and 131 respectively, except for the application of Temporary Gas Rate Adjustment Schedule 155. Schedule 155 is a temporary rate adjustment used to amortize the deferred natural gas costs approved by the Commission in the prior PGA. Because of their size, transportation service customers are analyzed individually to determine their appropriate share of deferred natural gas costs. The Company continues to analyze those customers to make sure that if those customers switch back to sales service, those customers would not receive natural gas costs deferrals which are not due them.

Q. Would you please explain which customers are eligible for service under Schedules 116 and 126?

A. Yes. Similar to Transportation Schedule 146, these Schedules provide transportation options available to smaller usage customers who choose to purchase their own supply of natural gas. These schedules charge the same base distribution rates as their respective Schedules 111 and 121. There are currently no customers who choose to take service on Schedules 116 and 126.

Q. How many Washington customers does the Company serve under each of its natural gas rate schedules?

A. As of December 2018, the Company provided service to the following number of Washington customers under each of its schedules:

Table No. 6 – Natural Gas Customers by Service Schedule

Rate Schedule	No. of Customers
General Service Schedules 101/102	163,850
Large General Service Schedules 111/112/116	3,115
Ex. Lg. General Service Schedules 121/122/126	3
Interruptible Sales Service Schedules 131/132	2
Transportation Service Schedule 146/148	47

Proposed Year 1 Rate Spread

Q. What is the proposed natural gas revenue increase, and how is the Company proposing to spread the increases by rate schedule?

A. The proposed base revenue increase is $12,935,000, or 13.8% in base margin[3]

[3] Base margin revenue refers to the base revenue associated with the Company's ownership and operation of its natural gas distribution operations. It is the revenue related to delivering natural gas to customers, and does not include the cost of natural gas, upstream third-party owned transportation, or the effect of other tariffs.

revenue. On a billed revenue basis, the increase is 10.1%. Provided below is a table showing the effect of the Company's proposed natural gas increase by rate schedule:

Table No. 7 - Proposed % Natural Gas Increase by Schedule (April 1, 2020)[4]

Rate Schedule	Increase in Margin Rates	Increase in Billing Rates
General Service Schedules 101/102	14.1%	10.4%
Large General Service Schedules 111/112/116	14.1%	9.2%
Interrupt. Sales Service Schedules 131/132	14.1%	6.2%
Transportation Service Schedule 146	14.1%	14.4%
Special Contracts Schedule 148	0.0%	0.0%
Overall	**13.8%**	**10.1%**

Q. Why isn't an increase percentage change shown for Large General Service Schedule 121/122 in the above table?

A. As part of this filing, the Company is proposing to combine Schedules 111/112/116 and 121/122/126 into single service schedules. There are presently only three customers taking service under Schedules 121/122 and, based on the nearly identical present rates and rate structures between the Schedules, it no longer makes sense to maintain these Schedules. I describe this in more detail later in my testimony.

Q. Is the proposed billing percentage increase for Transportation Schedule 146 comparable to the increase for the other service schedules?

A. No. The proposed billing percentage increase for Transportation Schedule 146 is not comparable to the proposed increases for the other (sales) service schedules, as Schedule 146 revenue does not include an amount for the cost of natural gas or upstream pipeline

[4] Schedule 148 is a banded-rate transportation tariff that allows for a negotiated service rate with large customers that have an economic alternative to taking natural gas distribution service from the Company. Contracts negotiated under Schedule 148 have fixed rates that do not vary with changes in base rates.

transportation (unlike the other service schedules). Transportation customers acquire their own natural gas and pipeline transportation. Including an estimate of 35.0 cents per therm for the cost of natural gas and upstream pipeline transportation, the proposed increase to Schedule 146 rates represents an average increase of approximately 3.0%.

Q. What information did the Company use to develop the proposed spread of the overall natural gas increase to the various rate schedules?

A. The Company believes that the results of the cost of service study (discussed later in my testimony) should be used as a guide to spread the general increase. The Company is also cognizant that most of the parties that participate in the Company's general rate cases are also involved in the on-going cost of service workshops stemming from the Company's 2016 general rate case.[5] Given the relative size of the proposed increase and the on-going cost of service workshops, Avista is proposing to spread the revenue increase on a uniform percent of margin basis. This proposed rate spread moves all rate schedules toward unity. Table No. 8 below shows the relative rates of return (schedule rate of return divided by overall rate of return) before and after application of the base rate increase:

[5] Docket Nos. UE-170002 and UG-170003

Table No. 8 – Present and Proposed Relative Rates of Return

Rate Schedule	Present Relative ROR	Proposed Relative ROR
General Service Schedules 101/102	0.67	0.77
Large General Service Schedules 111/112	2.73	2.22
Interruptible Sales Service Schedules 131/132	2.19	1.82
Transportation Service Schedule 146	1.16	1.03
Overall	**1.00**	**1.00**

Q. If the Commission were to order a revenue requirement lower than the Company's request, how does the Company propose to spread the revenue increase?

A. If the Commission were to order a lower revenue requirement, the Company proposes to allocate the same increase as the Company's initial filing to General Service Schedules 101/102. The Company also proposes that Transportation Service Schedule 146 continue to receive an equal percentage of margin increase. Any remaining revenue should then be applied equally to Schedules 111/112/116 and 131/132 as those schedules are providing significantly more than their relative cost of service as discussed below.

Proposed Year 1 Rate Design

Q. Would you please explain the present rate design within each of the Company's natural gas service schedules?

A. Yes. General Service Schedules 101/102 generally applies to residential and small commercial customers who use less than 200 therms/month. These schedules contain two energy rate blocks (0-70 therms, and over 70 therms), and a monthly customer/basic charge.

Large General Service Schedules 111/112/116 have a three-tier declining-block rate structure and are generally for customers who consistently use over 200 therms/month. These schedules consist of a monthly minimum charge plus a usage charge for the first 200 therms or less, and block rates for 201-1,000 therms/month and over 1,000 therms/month.

Extra Large General Service Schedules 121/122/126 have a five-tier declining-block rate structure with a monthly minimum charge plus a usage charge for the first 500 therms or less, and block rates for the next 500 therms, the next 9,000 therms, the next 15,000 therms, and usage over 25,000 therms/month. There is also an annual minimum requirement of 60,000 therms under the schedules.

Interruptible Sales Service Schedules 131/132 have a four-tier declining-block rate structure for the first 10,000 therms, the next 15,000 therms, the next 25,000 therms, and usage over 50,000 therms per month. The schedules also have an annual minimum deficiency charge based on a usage requirement of 250,000 therms per year.

Transportation Service Schedule 146 contains a monthly customer charge and a five-tier declining-block rate structure for the first 20,000 therms, the next 30,000 therms, the next 250,000 therms, the next 200,000 therms, and usage over 500,000 therms per month. The schedule also has an annual minimum deficiency charge based on a usage requirement of 250,000 therms per year.

Q. Is the Company proposing any changes to the present rate structures contained in its natural gas service schedules?

A. Yes. Over the past several years the Company has experienced a significant shift from customers moving from Extra Large General Service Schedules 121/122 to Large General Service Schedules 111/112. Because of the small amount of customers on Schedules 121/122, and the similar rate structures discussed below, the Company is proposing to eliminate Extra Large General Service Schedules 121/122/126 and merge them into the Large General Service

Schedules 111/112/116.

Q. Could you please explain in more detail the rationale for this proposal and under what Schedule those customers would be served if the Commission approves this proposal?

A. Schedules 121/122/126 exist for those customers who typically use over 10,000 therms per month. The rates under the Schedules are nearly identical to the rates under Large General Service Schedules 111/112/116, up to 10,000 therms. Schedules 121/122/126 include two additional block rates as compared to rate Schedules 111/112/116 with a fourth block rate for usage from 10,000 to 25,000 therms and a fifth block rate for usage over 25,000 therms. The Company proposes to eliminate Schedules 121/122/126, move those customers to Schedules 111/112/116, and add two additional block rates to Schedules 111/112/116. The proposed rate structure for Schedules 111/112/116 would then be nearly identical to the existing rate structure under Schedules 121/122/126. Existing Schedule 111/112/116 customers who use over 10,000 therms per month would see a (new) slightly lower rate for usage in excess of that level. Schedule 111/112/116 customers who use less than 10,000 therms per month would not see a change in their present rate structure. With the additional rate blocks under Schedules 111/112/116, present Schedules 121/122/126 customers would be served under a rate structure almost identical to the present Schedule 121/122/126 structure. Additionally, the Company will no longer need to monitor Schedule 121/122/126 customers for qualification under that Schedule.

Q. How many customers are presently served under Schedules 121/122/126?

A. There are presently <u>two</u> Schedule 121 customers, <u>one</u> Schedule 122 customer, and <u>zero</u> Schedule 126 customers.

Q. Would elimination of Schedules 121/122/126 be consistent with the rate schedules available in the Company's Idaho jurisdiction?

A. Yes. The Company eliminated Schedules 121/122 and merged them into Schedules 111/112 for similar reasons several years ago in the Company's Idaho jurisdiction.

Q. Where in your Exhibits do you show the present and proposed rates for the Company's natural gas service schedules?

A. Page 3 of Exh. JDM-7 shows the present and proposed rates under each of the rate schedules, including all present rate adjustments (adders). Column (g) on that page shows the proposed changes to the rates contained in each of the schedules.

Q. How does the Company propose to spread the proposed general revenue increase to the rates within Schedules 101/102?

A. Similar to electric, the Company proposes to <u>not</u> increase the monthly basic/customer charge from $9.50 per month. As shown in column (e), page 3 of Exh. JDM-7, Avista has proposed to increase the per therm rate for the two volumetric blocks on a uniform percentage basis. The first block (0-70 therms) would increase from $0.36723 to $0.43695, and the second block (over 70 therms) would increase from $0.47729 per therm to $0.56790 per therm.

Q. For April 1, 2020, what would be the increase in a residential customer's bill with average usage based on the proposed increase for Schedule 101?

A. The increase for a residential customer using an average of 66 therms of natural gas per month would be $4.60 per month, or 9.9%. A bill for 66 therms per month would increase from the present level of $46.40 to a proposed level of $51.00.

Q. Please explain the proposed changes in the rates for Large General Service Schedules 111/112/116.

A. The present rates for Schedules 101/102 and 111/112/116 provide a clear distinction for customer placement: customers who use less than 200 therms/month should be placed on Schedules 101/102, customers who consistently use over 200 therms per month should be placed on Schedules 111/112/116. Not only do the rates provide guidance for customer schedule placement, they provide a reasonable classification of customers for analyzing the costs of providing service.

The Company's proposed rates for Schedules 111/112/116 will maintain the rate structure within the schedules and continue to provide guidance for appropriate schedule placement for customers and a reasonable classification for cost analysis. The proposed minimum charge of $113.91 per month for Schedules 111/112/116 (for 200 therms or less) maintains the present relationship between the Schedules 101/102 and 111/112/116, and will minimize customer shifting.[6] The remaining proposed revenue increase for Schedules 111/112/116 was then spread on a uniform percentage increase of 13.5% to the remaining rate blocks.

Q. What would be the average increase for the three Schedule 121/122 customers when billed under the proposed Schedule 111/112 rates?

A. The average base rate increase for these three customers would be 13.5% which is consistent with the increase to the rate blocks.

[6] The calculation of the minimum charge for Schedules 111/112/116 is equal to the total bill for 200 therms priced at Schedule 101/102 base rates (excluding Schedule 150 gas costs).

Q. How is the Company proposing to spread the proposed increase of $28,000 to the rates under Interruptible Schedules 131/132?

A. The Company proposes to increase the first three block rates under the schedule by a uniform percentage increase of approximately 15.4%. The Company is not proposing to change the fourth block on Schedules 131/132 in order to provide for a more meaningful spread between the blocks.

Q. Please explain the proposed changes in the rates for Transportation Schedule 146.

A. The Company is proposing to adjust the basic charge by $75 per month, which is an increase from $550 to $625 per month. Unlike Schedules 101/102 and Schedules 111/112/116, Transportation Schedule 146 is not part of the Decoupling Mechanism and therefore the Company is proposing a basic charge increase to recover a larger portion of the fixed costs. For the remaining revenue requirement, the Company is proposing to spread the increase on a uniform percentage basis of approximately 14.1% to each of the present five block rates under the schedule.

Q. Turning now to Decoupling, how will new baseline information be incorporated into the natural gas Decoupling Mechanism?

A. As in the prior general rate case, the Company would, as a part of its Compliance Filing, submit the final baseline values for its natural gas Decoupling Mechanism prior to new rates going into effect as a result of this general rate case.

Q. Is the Company proposing any other changes to its natural gas service schedules?

A. Yes. In 2013 the Company made a housekeeping filing in an effort to show not only the actual distribution margin for the base tariff schedules as denoted by “Base Rate” on the tariff, but also provided a table detailing all of the other stand-alone schedules for purposes of showing the actual billing rate. The purpose was that by showing the base and billing rates on the same tariff sheet, customers could see what they are paying for each therm of natural gas.

While the intention behind this change made practical sense, it has proven to be administratively burdensome and difficult to keep the base tariff sheets updated in a timely manner with the actual billing rate in effect given the numerous rate changes that have occurred throughout the past years. Because the “Other Charges” section is not always able to be kept up to date and reflective of actual billing rates at the same time rate changes occur, it can be confusing to customers who see a difference between what is shown on the tariff and the billing rates they see on their monthly bills

Q. What is the Company proposing to the “Other Charges” portion of the tariff?

A. The Company is proposing to remove the rate components portion of the Other Charges section and reflect only base rates on the base tariff sheets. The Company proposes to continue to list all of the tariffs in effect under other charges so that customers are aware of all of the rate tariff components that make up the billing rates. The Company also provides a detailed “Shortcut Sheet” on its website which reflects all of the billing components that make up the present billing rates customers see on their bill each month.

Q. Have you made this change to your natural gas tariffs in other States?

A. Yes. In the Company's Idaho jurisdiction the Company, in consultation with Idaho Commission Staff, removed the rates under "Other Charges" for similar reasons and now only reflects the base tariff rates in effect. The Company has also proposed the same change in its Oregon jurisdiction in its current general rate case proceeding.

IV. TWO-YEAR RATE PLAN

Q. Would you please provide an overview of the Company's proposed Two-Year Rate Plan?

A. Yes. The electric and natural gas revenue requests, and resulting changes in customer's rates, discussed earlier in my testimony were specific to the rate changes proposed for April 1, 2020. As discussed by Company witnesses Mr. Vermillion and Ms. Andrews, the Company is proposing in this general rate case a Two-Year Rate Plan ("Rate Plan"). As a part of the request, the Company would receive a base rate increase effective April 1, 2020 (Rate Plan Year 1), and an increase in billed revenues on April 1, 2021 (Rate Plan Year 2).

For Rate Plan Year 2, for electric operations, there would be one rate adjustment associated with the application of the Revenue Growth Rate to the non-ERM authorized revenue (through tariff Schedule 96). For natural gas operations, there would be one annual adjustment associated with the application of the Revenue Growth Rate to non-gas cost authorized revenues (through tariff Schedule 196).

Q. As it relates to the revenue adjustments for Rate Plan Year 2, is Avista proposing to change base rates?

A. No, the Company is not proposing to change base rates in Rate Plan Year 2. To effectuate the Rate Plan revenue adjustments associated with the Revenue Growth Rate discussed by Ms. Andrews, the Company has filed Schedule 96 ("Rate Plan Adjustment - Electric") and Schedule 196 ("Rate Plan Adjustment – Natural Gas). Schedules 96 and 196, which would go into effect at the same time as the base rate tariffs on or about April 1, 2020, and provide the rates for all two years of the Rate Plan. For Rate Plan Year 1, the rates would be set at $0.00000/kWh and $0.00000/therm. These rates reflect the fact that the base rate increases in Rate Plan Year 1 would occur in base rates and not through Schedules 96 and 196. The tariffs (Schedules 96 and 196) then provide the rates for Rate Plan Year 2, which would be in effect starting April 1, 2021 until such time as the revenues collected through Schedules 96 and 196 are incorporated in base rates.

Q. What is the Company's proposed electric rate spread and rate design for Rate Plan Year 2?

A. For electric operations, the proposed rate spread for the April 1, 2020 base rate increase will move Schedules 1/2 and 11/12 closer to unity as discussed earlier. To continue this movement, Avista used a pro-rata allocation of the Company's April 1, 2020 rate spread percentages for the rate spread related to the Schedule 96 revenue increases for April 1, 2021. For rate design, the Company proposes to spread the revenue increase for each schedule on a uniform cents per kWh basis to the variable energy rates (per kWh rates).

The proposed electric increase to each customer rate schedule effective April 1, 2021, is shown in Table No. 9 below:

<u>Table No. 9 – Proposed % Electric Increase by Schedule (April 1, 2021)</u>

Rate Schedule	Increase in Base Rates	Increase in Billing Rates
Residential Schedules 1/2	3.8%	3.7%
General Service Schedules 11/12	2.8%	2.7%
Large General Service Schedules 21/22	3.5%	3.3%
Extra Large General Service Schedule 25	3.5%	3.3%
Pumping Service Schedules 31/32	3.5%	3.3%
Street & Area Lights Schedules 41-48	0.0%	0.0%
Overall	**3.5%**	**3.3%**

Q. For April 1, 2021, what is the proposed monthly bill increase for a residential electric customer with average consumption?

A. The proposed monthly bill increase for a residential customer using an average of 918 kWhs per month is $3.46 per month, or a 3.9% increase in their electric bill. The present bill for 918 kWhs, after the year 1 increase, is $89.14 compared to the proposed level of $92.60, including all rate adjustments.

Q. What is the Company's proposed natural gas rate spread and rate design for Rate Plan Year 2?

A. For natural gas operations, the Rate Plan revenue increase for April 1, 2021 was spread in the same manner as the April 1, 2020 base rate increase, on a uniform percent of margin basis. For rate design, the Company spread the revenue increase for each schedule on a uniform cents per therm basis to the variable energy rates (per therm rates).

The proposed natural gas increase to each customer rate schedule effective April 1, 2021, is shown in Table No. 10 below:

<u>Table No. 10 – Proposed % Natural Gas Increase by Schedule (April 1, 2021)</u>

Rate Schedule	**Increase in Margin Rates**	**Increase in Billing Rates**
General Service Schedules 101/102	6.2%	4.7%
Large General Service Schedules 111/112/116	6.2%	4.2%
Interrupt. Sales Service Schedules 131/132	6.2%	2.9%
Transportation Service Schedule 146	6.2%	6.3%
Special Contracts Schedule 148	0.0%	0.0%
Overall	**6.1%**	**4.6%**

Q. For April 1, 2021, what would be the increase in a residential customer's bill with average usage based on the proposed increase for Schedule 101?

A. The increase for a residential customer using an average of 66 therms of natural gas per month would be $2.55 per month, or 5.0%. A bill for 66 therms per month would increase from the present level, after the year 1 increase, of $51.00 to a proposed level of $53.55.

Q. Where in your exhibits do you show the proposed increases by Schedule, and resulting rates, related to year 2 of the Rate Plan?

A. For the electric Rate Plan revenue adjustments, Exh. JDM-4, page 4 provides the revenue increases for year 2 of the Rate Plan, and page 5 provides the volumetric energy rates. These rates are also provided in the Company's filed tariff, Original Sheet 96.

For the natural gas Rate Plan revenue adjustments, Exh. JDM-7, page 4 provides the revenue increases for year 2 of the Rate Plan, and page 5 provides the volumetric energy rates. These rates are also provided in the Company's filed tariff, Original Sheet 196.

Q. How do the Rate Plan Components interact with the Company's Decoupling Mechanisms?

A. Presuming that the Commission approves Avista's request to extend the life of our Decoupling Mechanisms (as discussed by Mr. Ehrbar), for the first year of the Rate Plan, with rates effective on or before April 1, 2020, the baseline values for the electric and natural gas Decoupling Mechanisms would be provided as a part of the Compliance Filing that occurs before new rates go into effect. The new base for the electric and natural gas Decoupling Mechanisms cannot be determined until the Commission issues its final order.

For Rate Plan Year 2, Avista would file new baseline values for the electric and natural gas Decoupling Mechanisms on or before January 15, 2021. For the electric and natural gas Decoupling Mechanisms, the new baseline values would reflect the Rate Plan revenue increases that would take effect on April 1, 2021. Those revenue increases would be added to the "Total Rate Revenue" in the mechanisms.

V. NATURAL GAS REVENUE NORMALIZATION

Q. Would you please describe the natural gas revenue normalization adjustment included in Company witness Ms. Andrews's pro forma study?

A. Yes. Similar to the electric revenue normalization adjustment, sponsored by Ms. Knox, 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 6 is a Commission Basis weather normalization restating adjustment. Revenues for this adjustment are based on rates that were in effect during the January 2018 through December 2018 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 6, which removes the impact of adder schedule revenues and related expenses during the January 2018 through December 2018 test period.

3. Pro Forma Revenue Normalization: The Pro Forma Revenue Normalization Adjustment in column 3.01 of Exh. EMA-3, page 8, adjusts January 2018 through December 2018 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 2018, as if the May 1, 2018 base tariff rates were effective for the full 12-months of the test year.

<u>Weather Normalization:</u>

Q. Beginning 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 480-90-257. 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 the past cases, 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 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 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 2007 through December 2016. 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 1989 through 2018.

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 No. UG-170486. 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 12-months ended December 2018 test year?

A. Weather was warmer than normal during the January 2018 through December 2018 period. The adjustment to normal required the addition of 447 heating degree-days from January through June and October through December.[7] The adjustment to sales volumes was an addition of 9,164,130 therms which is approximately 3.4 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 $6,259,000, which after the offsetting reduction to purchased gas expense of $2,655,000, resulted in an increase to distribution margin of $3,604,000. The combined effect of netting the increase to distribution margin against the decoupling revenue offset of $3,321,000, resulted in a net margin weather adjustment of $283,000.[8] After an offsetting reduction for revenue related expenses and taxes, the weather normalization adjustment produced an increase to net operating income of $5,000, as shown below:

General Business Revenue (Sales)	$	6,259
Other Revenue (Decoupling Deferred)	$	(3,321)
Total Revenue (Net Adjustment)	$	2,938
Less: Purchased Gas Expense	$	(2,655)
Distribution Margin Weather Adjustment	$	283
Less: Revenue Related Expenses	$	(277)
Less: Federal Income Tax	$	(1)
Net Operating Income	$	5

[7] 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.
[8] The Decoupling Mechanism went into effect January 1, 2015.

Eliminate Adder Schedules:

Q. Moving on to the second revenue normalizing adjustment, 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: Schedule 174 Temporary Tax Rebate Rate Adjustment, 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 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.

Pro Forma Revenue Normalization:

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 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 2018 through December 2018 test period, as if the base tariff rates effective May 1, 2018 (Docket No. UG-170486) 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 $511,000. The combined effect of the decrease to revenue from rates with the elimination of both the 2018 restated decoupling deferred revenue (-$2,368,000) and the 2018 provision for refund from tax reform (-$2,181,000), resulted in a total pro forma revenue adjustment decrease of $2,055,000. After an offset for revenue-related expenses and taxes, Washington net operating income increased $404,000, as shown below, and in column 3.08 on page 8 of Exh. EMA-3.

General Business Revenue	$ (58,123)
Other Revenue (Eliminate Decoupling Deferred)	$ 2,368
Other Revenue (Eliminate Provision for Refund)	$ 2,181
Total Revenue (Net Adjustment)	$ (53,574)
Eliminate Purchased Gas Expense	$ 51,519
Distribution Margin Adjustment	$ (2,055)
Revenue Related Expenses	$ 2,566
Federal Income Tax	$ (107)
Net Operating Income	$ 404

VI. 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-170486, UG-160229, UG-150205, UG-140189, and UG-120437.

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. Exh. JDM-8 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 Exh. JDM-9 is based on the twelve months ended December 2018 test year pro forma results of operations presented by Company witness Ms. Andrews in Exh. EMA-3.

Q. Would you please explain the cost of service study presented in Exh. JDM-9?

A. Yes. Exh. JDM-9 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 utilized as a consideration to inform the rate spread and rate design discussed previously. 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-170486. The Company is cognizant that there is an ongoing cost of service docket underway that is analyzing many aspects of how parties conduct cost of service studies. It is the Company's belief that no major cost of service methodology changes should occur until after the culmination of those proceedings. Accordingly, the proposed rate spread is done on an equal percentage of margin basis to preserve, as much as possible, the status quo.

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 four-part factor allocator (four-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 four-factor. A detailed description of the methodology is included in Exh. JDM-8.

<u>Distribution Main Cost Allocation</u>

Q. Is the Company's approach to the allocation of distribution mains consistent with what was proposed in the Company's last several general rate cases?

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 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 explain the concern the Company is addressing through its proposed distribution main allocation.

A. 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[9]. The allocation the Company used in its prior general rate case filings (prior to UG-150205) separated distribution main investment into 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 <u>any</u> 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

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[9] See the testimony of Commission Staff witness Mr. Mickelson in Docket Nos. UG-140189 and UG-120437.

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 on a peak day. 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-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 average demand and how much would be allocated based on peak demand[10]. 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.

[10] Peak demand is defined as the average of the five-day sustained peaks from each of the most recent three years.

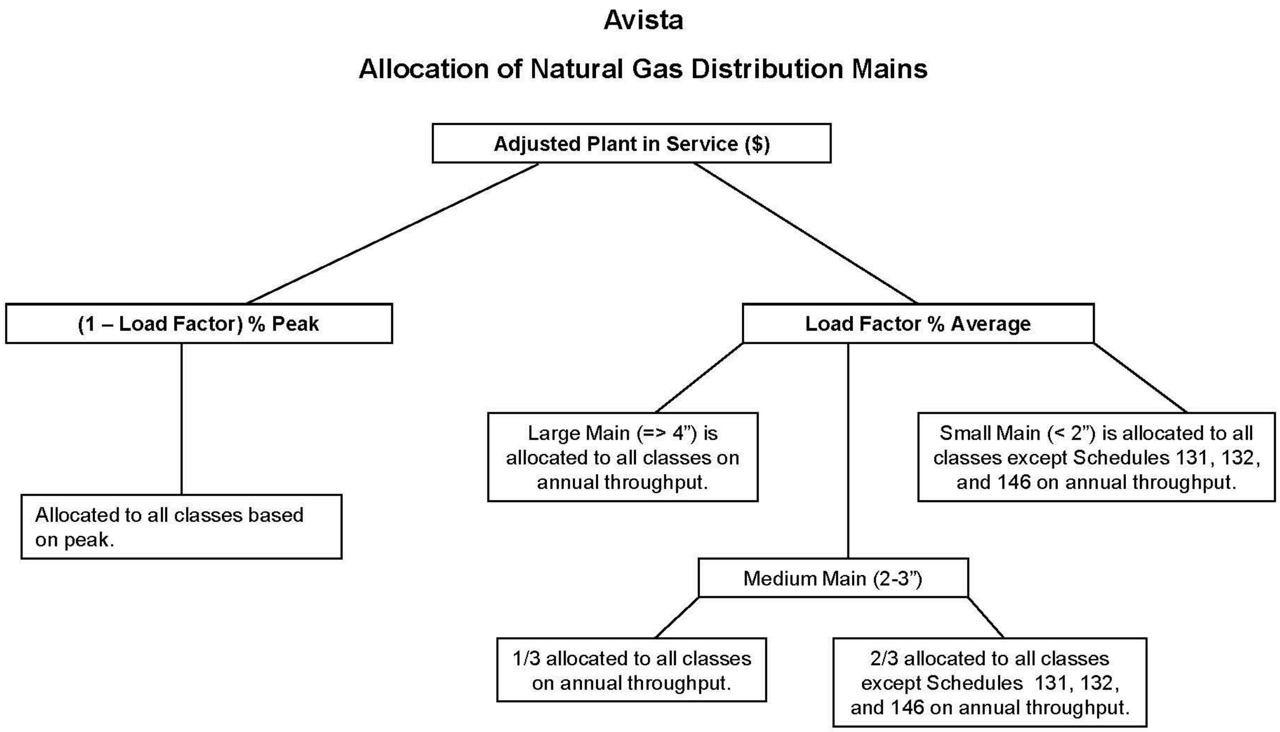
The resulting load factor was used to divide the demand-related costs into peak demand and average demand for purposes of allocating the costs to the rate schedules, with the demand-related costs being allocated 38.3 percent on average demand and 61.7 percent on peak demand. The load factor provides 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 natural 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.

Illustration No. 1:



First, the total distribution mains plant of $249.4 million was divided into the portion to be allocated based on peak demand and the portion to be allocated based on average demand using the system load factor described above. This resulted in $95.5 million (38.3 percent) of plant allocated based on average demand, and $153.9 million (61.7 percent) allocated based on peak demand.

Second, the $153.9 million, or 61.7 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 $95.5 million, or 38.3 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 natural 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 natural 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 natural gas distribution network. Large customers benefit because the Company has small main throughout its distribution system which is interconnected with large main. This interconnectedness helps to minimize pressure drop on a peak day and keep reliability up. While large customers 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 natural 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[11] and Commission Staff[12] 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 natural gas distribution system of medium to large mains as a whole, and not solely from the actual main through which natural 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

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

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 customers, however the benefits, and therefore assigned cost, should be higher than traditionally assigned. Finally, the Company's methodology is simple 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-170034, 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 four-factor allocator. This allocation factor is used on all common plant and other A&G expenses and 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. Has the four-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).

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) is providing less than the overall rate of return (unity), and Large General, Interruptible, and Transportation Schedules (111/112/116, 131/132 and 146) are providing more than unity. Table No. 11 shows the rate of return and the relative return ratio at present rates for each rate schedule.

Table No.11: Base Case Results

Rate Schedule	Rate of Return	Return Ratio
General Service Schedules 101/102	345.00%	0.68
Large General Service Schedules 111/112/116	13.59%	2.68
Interruptible Sales Service Schedules 131/132	11.10%	2.19
Transportation Service Schedule 146	5.80%	1.14
Total Washington Natural Gas System	5.07%	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.