Exh. JCA-1T

WUTC DOCKET: UE-200900 UG-200901 UE-200894
EXHIBIT: JCA-1T
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BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UG-20_____

DIRECT TESTIMONY OF

JOEL C. ANDERSON

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

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

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

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

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

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

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

A. Yes. I am sponsoring Exh. JCA-2 related to the natural gas cost of service study. This exhibit was prepared by me and consists of summaries of information derived from the Cost of Service Study. I am also sponsoring Exh. JCA-3 related to AMI costs and benefits components of the natural gas cost of service study.

II. SUMMARY

Q. Please briefly summarize your testimony related to the natural gas cost of service study.

A. I believe the Base Case cost of service study presented in this case is a fair representation of the costs to serve each customer group. The cost of service study indicates that General Service Schedules 101/102 (serving mostly residential customers) and Transportation Schedule 146 are under parity as the classes provide less than the overall rate of return under present rates. The other classes, Large General and Interruptible Schedules

(111/112/116, 131/132) are over parity as they provide more than the overall rate of return at present rates. Table No. 1 shows the rate of return and the relationship of the customer class return to the overall return (relative return ratio) at present rates for each rate schedule as well as the revenue-to-cost parity ratio at present rates for each rate schedule:

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

Rate Schedule	Rate of Return	Return Ratio	Parity Ratio
General Service Schedule 101/102	3.42%	0.66	0.91
Large General Service Schedules 111/112	15.29%	2.96	1.70
Interruptible Sales Service Schedule 132	11.02%	2.14	1.40
Transportation Service Schedule 146	4.42%	0.86	0.91
Total Washington Natural Gas System	5.16%	1.00	1.00

III. NATURAL GAS REVENUE NORMALIZATION

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

A. Similar to the electric revenue normalization adjustment, sponsored by 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 2019 through December 2019 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 2019 through December 2019 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 2019 through December 2019 test period customers and usage for any known and measurable (pro forma) changes. In addition, the adjustment re-prices billed, unbilled, and weather adjusted usage at the base tariff rates approved for 2020, as if the April 1, 2020 base tariff rates were effective for the full 12 months of the year.[1]

Weather Normalization:

Q. Beginning with the first revenue normalizing adjustment, what is the Commission Basis weather normalization adjustment?

A. Weather normalization is a required element of Commission Basis reporting pursuant to WAC 480-90-257. The intent of this adjustment is for Commission Basis adjusted revenues and natural gas costs to reflect operations under normal temperature conditions during the reporting period.

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

A. Yes. As in past cases, the natural gas weather normalization adjustment is developed from a regression analysis of 10 years of billed usage per customer and billing period heating degree-day data. The resulting seasonal weather sensitivity factors (use-per-customer-per-heating-degree day) are multiplied by the monthly test period number of customers, which

[1] Docket No. UG-190335

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 10-year period January 2009 through December 2018. Is this true for natural gas as well?

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

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

A. Normal heating degree-days are based on a rolling 30-year average of heating degree-days reported for each month by the National Weather Service for the Spokane International Airport weather station. Each year the normal values are adjusted to capture the most recent year with the oldest year dropping off, thereby reflecting the most recent information available at the end of each calendar year. The calculation includes the 30-year period from 1990 through 2019.

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

A. Yes. The process for determining the weather sensitivity factors and the monthly adjustment calculation is consistent with the methodology presented in Docket UG-190335. This methodology has been used in every case since it was introduced in Docket UG-070805.

Q. What was the impact of natural gas weather normalization on the 12-months ended December 2019 test year?

A. Weather was colder than normal during the January 2019 through December 2019 period. The adjustment to normal required a decrease of 229 heating degree-days from January through June and October through December.[2] The adjustment to sales volumes was a decrease of 5,787,854 therms which is approximately 3.8 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 decreased total natural gas revenue by $3,931,000, which after the offsetting increase to purchased gas expense of $1,658,000, resulted in a decrease to distribution margin of $2,273,000. The combined effect of netting the decrease to distribution margin against the decoupling revenue offset of $2,095,000, resulted in a net margin weather adjustment of $(178,000).[3] After an offsetting increase for revenue related expenses and taxes, the weather normalization adjustment produced a decrease to net operating income of $6,000, as shown below:

Table No. 2: - Summarize Weather Normalization Adjustment

General Business Revenue (Sales)	$	(3,931,000)
Other Revenue (Decoupling Deferred)	$	2,095,000
Total Revenue (Net Adjustment)	$	(1,836,000)
Less: Purchased Gas Expense	$	1,658,000
Distribution Margin Weather Adjustment	$	(178,000)
Less: Revenue Related Expenses	$	171,000
Less: Federal Income Tax	$	1,000
Net Operating Income	$	(6,000)

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

<u>Eliminate Adder Schedules:</u>

Q. Moving on to the <u>second revenue normalizing</u> 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 the purchased gas cost related accounts into the "City Gate Purchases" line item in order to simplify the Pro Forma Revenue Normalization adjustment described below.

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

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

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

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

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

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 $6,011,000. The combined effect of the decrease to revenue from rates with the elimination of both the 2019 restated decoupling deferred revenue $1,188,000 and the 2019 provision for refund from tax reform (-$325,000), resulted in a total pro forma revenue adjustment increase of $8,551,000. After an offset for revenue-related expenses and taxes, Washington net operating income increased $8,187,000, as shown below, and in column 3.01 on page 8 of Exh. EMA-3.

Table No. 3 – Summarize Revenue Normalization Adjustment

General Business Revenue	$	(41,734,000)
Other Revenue (Eliminate Decoupling Deferred)	$	(1,188,000)
Other Revenue (Eliminate Provision for Refund)	$	325,000
Total Revenue (Net Adjustment)	$	(42,597,000)
Eliminate Purchased Gas Expense	$	51,148,000
Distribution Margin Adjustment	$	8,551,000
Revenue Related Expenses	$	1,812,000
Federal Income Tax	$	(2,176,000)
Net Operating Income	$	8,187,000

IV. NATURAL GAS COST OF SERVICE

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

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

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

A. The cost of service study provided by the Company as Exh. JCA-2 is based on the 12-months ended December 2019 test year pro forma results of operations presented by Ms. Andrews in Exh. EMA-3.

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

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

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

Cost of Service Rulemaking

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

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

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

599?

A. Yes. Commission Staff initiated the generic cost of service collaborative in 2017 in response to the Final Order in Avista's 2016 general rate proceeding (Dockets UE-160228 and UG-160229). Avista participated in Staff's information gathering efforts and multiple workshops over three years as the collaborative evolved into the UE-170002 and UG-170003 rulemaking proceedings.

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

A. The stated purpose of establishing the collaborative was to "provide an opportunity to establish greater clarity and some degree of uniformity in cost of service studies going forward".[4] The intention was refined and evolved over the course of the collaborative into the purpose stated as WAC 480-85-010:

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

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

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

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

<u>Study Inputs – Load Study</u>

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

A. Other than a conflict with section 050, the Company believes the natural gas cost of service study presented in this filing meets all the requirements set forth in WAC 480-85. With that said, the requirements of WAC 480-85 have required extensive modifications to the cost of service model in order to meet both the presentation requirements and new data requirements associated with the allocation methods within section 060. The Company has interpreted the new requirements to the best of our ability and used the best available sources of information to us at the time of filing when preparing the cost of service study.

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

A. WAC 480-85-050(1) requires usage data for the study to come from the best available source, preferably advanced metering technology. The Company is presently in the process of implementing AMI for its Washington customers. The implementation was just beginning during the 2019 test year, therefore consistent daily data representative of all customers during the test year is not available. Therefore, the Company falls under sub-section (d) requiring the use of a load study.

Q. Was a Load study provided in conjunction with this Cost of Service Study?

A. No. Consistent with the comments Avista provided on March 27, 2020 in Dockets UE-170002 and UG-170003 the Company is presently in the process of completing implementation of AMI for its Washington customers, as discussed by Company witnesses Ms. Rosentrater and Mr. DiLuciano. Avista's first natural gas load study will be conducted after the full implementation of AMI. The Company does not believe that conducting an expensive new load study prior to the completion of its AMI meters project, likely by a third-party entity, would be a prudent use of resources for customers to incur given the imminent availability of the AMI data. The Company asked for flexibility in this type of situation as the Company completes its transition to full deployment of AMI meters during the pendency of the cost of service rulemakings. As shown on page 1 of Appendix A to the adoption Order Commission Staff stated that it "understands the concerns of stakeholders about implementation and will ask that the Commission take it into consideration." The Company is filing a petition for limited exemption from WAC 480-85-050(1) concurrent with this filing from the requirement that rate schedule usage must come from AMI (not fully implemented) or a load study (does not exist) for purposes of the natural gas cost of service study.

Q. Do you believe that if the Company would have conducted a new load study with daily usage for all rate schedules it would have a material impact on the results of the cost of service study in this proceeding?

A. No. While it is reasonable to assume that a load study with daily usage by rate schedule would help the shaping of daily demand estimates used in developing the design day peak allocation factors, the Company does not believe this would have a material effect on the directional accuracy of the study results given that the majority of rate schedules are significantly above or below rate parity.

<u>Methodology</u>

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

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

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

The Excel model used to calculate the base case cost of service and supporting schedules have been included in its entirety electronically and hard copy in the workpapers accompanying this case. While there are macros to facilitate printing certain workpapers, no macros are integral to the cost of service model calculations.

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

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

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

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

The Company used the system load factor to determine how much of the demand-related costs would be allocated based on annual throughput and how much would be allocated based on design day peak demand[5]. A system load factor was calculated based on weather-normalized throughput and design day 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

[5] Peak demand is defined as the hypothetical design day demand.

and average demand for purposes of allocating the costs to the rate schedules, with the demand-related costs being allocated 35.2 percent on average demand and 64.8 percent on peak demand. The load factor provides a reasonable basis for determining what portion of the costs should be allocated based on average demand.

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

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

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

A. Property insurance and taxes are functionalized and allocated based on plant in service. Pensions and employee insurance expenses are allocated based on salary and wages. FERC fees are identified and allocated based on energy consumption. Revenue based fees, uncollectible accounts expenses, and excise taxes are allocated by relative share of total revenue. The remainder of general plant, intangible plant and other A&G expenses are considered common costs and are allocated based on the Company's four-factor. This allocation factor is the cost of service equivalent of the four-factor allocator used in the Company's results of operations reporting. The four-factor has historically been utilized by the Company to allocate common operating costs and plant between states (Washington, Idaho, and Oregon) and among services (electric and natural gas) for purposes of the Company's Commission Basis results of operations.

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

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

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

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

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

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

A. Yes. Account 303.120 software costs are associated with the meter data management system (MDM) and advanced metering infrastructure (AMI) project. An analysis of Account 303.100 computer software by project is included in the Company workpapers. No additional functionalization resulted from the project level analysis. Common intangible plant costs have been allocated based on tangible plant. This treatment of intangible plant costs is consistent with the Company's past natural gas cost of service studies.

<u>Results</u>

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

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

Table No. 4 - Base Case Results

Rate Schedule	Rate of Return	Return Ratio	Parity Ratio
General Service Schedule 101/102	3.42%	0.66	0.91
Large General Service Schedules 111/112	15.29%	2.96	1.70
Interruptible Sales Service Schedule 132	11.02%	2.14	1.40
Transportation Service Schedule 146	4.42%	0.86	0.91
Total Washington Natural Gas System	5.34%	1.00	1.00

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

V. AMI COSTS AND BENEFITS BY RATE CLASS

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

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

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

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

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

A. Yes it does.