Exhibit No. __ (RJA-1T)
Docket No. UG-17___
Witness: Ronald J. Amen

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION Respondent.	DOCKET UG-17____

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF RONALD J. AMEN

August 31, 2017

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Ronald J. Amen and my business address is 17806 NE 109th Court, Redmond, Washington 98052.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Cascade Natural Gas Corporation ("Cascade" or the "Company").

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch Management Consulting, LLC ("Black & Veatch") as a Director and I am a member of the Advisory & Planning Practice within Black & Veatch.

Q. Please describe the firm of Black & Veatch.

A. Black & Veatch Corporation has provided comprehensive engineering and management services to utility, industrial, and governmental entities since 1915. Black & Veatch Management Consulting, LLC delivers management consulting solutions in the energy and water sectors. Our services include broad-based strategic, regulatory, financial, and information systems consulting. In the energy sector, Black & Veatch delivers a variety of services for companies involved in the generation, transmission, and distribution of electricity and natural gas.

Black & Veatch has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis, and regulatory practices and policies gained through management and operating responsibilities at gas distribution, pipeline, and other energy-related companies, and through a wide variety of client assignments. Black & Veatch has assisted numerous gas distribution companies located in the U.S. and Canada.

Q. What has been the nature of your work in the utility consulting field?

A. I have over 39 years of experience in the utility industry, the last 20 years of which have been in the field of utility management and economic consulting. Specializing in the natural gas industry, I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, resource planning issues, strategic business planning, merger and acquisition analysis, organizational restructuring, new product and service development, and load research studies. I have prepared and presented expert testimony before utility regulatory bodies and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included as Exhibit No. __ (RJA-8) to my testimony.

Q. Have you testified previously before the Washington Utilities and Transportation Commission ("Commission" or "WUTC")?

A. Yes. I have testified in Docket Nos. UG-931405 (General Rate Case of Washington Natural Gas Company ("WNG")), UG-940814/UG-940034 (Cost of Service and Rate Design Proceeding of WNG), UG-941246/UG-950264 (WNG Line Extension Policy), UG-950278 (General Rate Case of WNG), UE-960195 (Merger of Washington Energy

Company and Puget Sound Power and Light Company), UG-960520 (WNG Propane Service), UG-011571 (General Rate Case of Puget Sound Energy), UG-060267 (General Rate Case of Puget Sound Energy), UG-080546 (General Rate Case of NW Natural), and UG-152286 (General Rate Case of Cascade Natural Gas). I have also previously appeared before the Commission on numerous occasions regarding various regulatory, customer contract and tariff matters.

Q. Have you previously testified before any other utility regulatory bodies?

A. Yes. I have presented expert testimony before the Federal Energy Regulatory Commission ("FERC") and numerous state and provincial regulatory commissions.

Q. Please summarize your testimony.

A. In my testimony I present Cascade's Cost of Service Study ("COSS") and discuss its results, and I present the various rate design proposals filed by Cascade in this proceeding.

My testimony consists of this introduction and summary section and the following additional sections:

- Theoretical Principles of Cost Allocation
- Cascade's COSS
- Principles of Sound Rate Design
- Determination of Proposed Class Revenues
- Cascade's Rate Design Proposals
- Residential & Non-Residential Class Bill Impacts
- Determination of Gas Resource Demand Costs by Customer Class for Use in Cascade's PGA Filings

Q. Please provide a list of exhibits supporting your testimony.

A. The following exhibits accompany my testimony.

- Exhibit No. __ (RJA-2) Summary of COSS results
- Exhibit No. __ (RJA-3) Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
- Exhibit No. __ (RJA-4) Analysis of Revenue by Detailed Tariff Schedule
- Exhibit No. __ (RJA-5) Residential Impact by Month
- Exhibit No. __ (RJA-6) Impact of Recommended Rate Changes
- Exhibit No. __ (RJA-7) Determination of Gas Resource Demand Costs by Customer Class
- Exhibit No. __ (RJA-8) Resume of Ronald J. Amen

II. THEORETICAL PRINCIPLES OF COST ALLOCATION

Q. Why do utilities conduct cost allocation studies as part of the regulatory process?

A. There are many purposes for utilities conducting cost allocation studies, ranging from designing appropriate price signals in rates to determining the share of costs or revenue requirements borne by the utility's various rate or customer classes. In this case, an embedded COSS is a useful tool for determining the allocation of Cascade's revenue requirement among its customer classes. It is also a useful tool for rate design because it can identify the important cost drivers associated with serving customers and satisfying their design day demands.

Q. Please describe the various types of cost of service studies that may be useful to a utility for rate design and the allocation of revenue requirements.

A. In general, cost of service studies can be based on embedded costs or marginal costs. Marginal costs can be thought of as the incremental change in costs associated with a one unit change in service (or output) provided by the utility. As a result of using an incremental change, capacity additions tend to be lumpy – meaning that they may add more capacity than required to serve the increment of load assumed in the analysis. To avoid this issue requires that the computation of the unit cost be based on the amount of capacity added rather than on the level of load that can be served.

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (an historical period) or the estimated book value of costs for a forecast test year or some combination of historical and future costs. Where a forecast test year is used, the costs and revenues are typically derived from budgets prepared as part of the utility's financial plan. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

Marginal cost studies can reflect actually incurred costs but often rely on estimates of the expected changes in cost associated with changes in utility service. Marginal cost studies are forward-looking to the extent permitted by available data. Marginal cost studies may be particularly useful for rate design and can also be used as a guide to determine how a utility's total revenue requirement should be allocated to its classes of service. Where it is important to send appropriate price signals associated with additional energy consumption by customers, an understanding of marginal cost may be useful. For a gas utility, detailed studies are not required to assess the impact of additional consumption by existing customers since the delivery system is built for design day requirements and energy conservation has reduced those requirements for most customers. Where new customers are added to the system, growth may increase design day requirements above an amount that existing facilities can serve. The principal factors driving new main investment are customer growth and the replacement of aging pipeline infrastructure such as bare steel and cast iron mains to provide safe and reliable service for customers.

Q. Please discuss the reasons that cost of service studies are utilized in regulatory proceedings.

A. Cost of service studies represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more classes, or the cost of providing multiple products to the same class, use the same facilities and the use by one class precludes the use by another class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of throughput, while variable costs change directly with changes in throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains and service lines, meters, and regulators. The distribution assets of a gas utility do not vary with the level of throughput in the short run. In the long run, main costs vary with either growing design day demand or a growing number of customers.

Finally, utility costs exhibit significant economies of scale. Scale economies result in declining average cost as gas throughput increases and marginal costs must be below average costs. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies, on either a marginal or embedded cost basis, requires an understanding of the operating characteristics of the utility system. Further, as discussed below, different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Q. Please discuss the application of economic theory to cost allocation.

A. The allocation of costs using cost of service studies is not a theoretical economic exercise. It is rather a practical requirement of regulation since rates must be set based on the cost of service for the utility under cost-based regulatory models. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing that revenue requirement. Using the cost information per unit of demand, customer, and energy developed in the cost of service study to understand and quantify the allocated costs in each customer class is a useful step in the rate design process to guide the development of rates.

However, the existence of common costs makes any allocation of costs problematic from a strict economic perspective. This is theoretically true for any of the various utility costing methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy-free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy-free so long as the price exceeds marginal cost, but is less than stand-alone costs ("SAC"). The logic for this concept is that if customers' prices exceed marginal cost, those customers make a contribution to the fixed costs of the utility. All other customers benefit from this contribution to fixed costs because it reduces the cost they are required to bear. Prices must be below the SAC because the customer would not be willing to participate in the service offering if prices exceed SAC.

SAC is an important concept for Cascade because certain customers have competitive options for the end uses supplied by natural gas through the use of alternative fuels. As a result, subsidy-free prices permit all customers to benefit from the system's scale and common costs, and all customers are better off because the system is sustainable. If strict application of the cost allocation study suggests rates that exceed SAC for some customers, prices must nevertheless be set below the SAC, but above marginal cost, to ensure that those customers make the maximum practical contribution to the common costs of the utility.

Q. If any allocation of common cost is problematic from a theoretical perspective, how is it possible to meet the practical requirements of cost allocation?

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of *cost causation*. Cost causation, as alluded to earlier, addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs. To answer this question, it is necessary to establish a linkage between a Local Distribution Company's ("LDC's") customers and the particular costs incurred by the utility in serving those customers.

An important element in the selection and development of a reasonable COSS allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off-peak gas service.

Q. Why are the relationships between customer requirements, load profiles and usage characteristics significant to cost causation?

A. The Company's distribution system is designed to meet three primary objectives: (1) to extend distribution services to all customers entitled to be attached to the system; (2) to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. There are certain costs associated with each of these objectives. Also, there is generally a direct link between the manner in which such costs are defined and their subsequent allocation.

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

Demand or capacity related costs are associated with plant that is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as the transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to the Company's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent they vary with the amount of gas volumes purchased by the Company for its sales service customers.

From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred for a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by customer class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the manner in which customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer’s load characteristics. These meters have different costs based on size and type. Therefore, meter costs are customer-related, but differences in the cost of meters are reflected by using a different meter cost for each class of service. For some classes such as the largest customers, the meter cost may be unique for each customer.

Q. How does one establish the cost and utility service relationships you previously discussed?

A. To establish these relationships, the Company must analyze its gas system design and operations, its accounting records as well as its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. Please explain what you mean by the term "direct assignment."

A. The term direct assignment relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a COSS, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by a special study as is done with costs associated with meters and services.

Q. What prompts the analyst to elect to perform a special study?

A. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q. How do you determine whether to directly assign costs to a particular customer or customer class?

A. Direct assignments of plant and expenses to particular customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?

A. No. The nature of utility operations is characterized by the existence of common or joint use facilities, as mentioned earlier. Out of necessity, then, to the extent a utility's plant and expense cannot be directly assigned to customer groups, common allocation methods must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q. Were direct assignments of plant made in the Cascade COSS?

A. Yes. A special study was performed to determine the specific transmission and distribution mains, as well as the customer service lines, that were constructed to serve Cascade's Special Contract customers. The plant costs related to these facilities were directly assigned to the Special Contract class in the COSS. The Company's Geographic Information System ("GIS") was queried to research the various pipeline pathways from system regulator stations to the customers' service addresses along with the related pipeline sizes, material types, and pressure classification. Historical plant records such as work orders, distribution line reports, facilities installation diagrams, statistical data sheets, and gas service record cards were reviewed to obtain the necessary facilities data and construction cost information to complete the direct assignment of the mains and services plant costs to the Special Contracts class.

III. CASCADE'S COSS

A. Process Steps and Structure of the Cost of Service Study

Q. Please describe the process of performing Cascade's COSS analysis.

A. Three broad steps were followed to perform the Company's COSS: (1) functionalization, (2) classification, and (3) allocation. The first step, functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. The Company's functional cost categories associated with gas service include: production (i.e., gas supply), transmission, distribution and general. Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics previously discussed: (1) customer, (2) demand or capacity, and (3) commodity. The final step is the allocation of each functionalized and classified cost element to the individual customer class. Costs typically are allocated on customer, demand, commodity or revenue allocation factors.

Q. Are there factors that can influence the overall cost allocation framework utilized by a gas utility when performing a COSS?

A. Yes. The factors which can influence the cost allocation used to perform a COSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q Why are these considerations relevant to conducting Cascade's COSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study was conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the State of Washington as it pertains to cost of service studies and gas ratemaking issues.

Q. Please explain why the physical configuration of the system is an important consideration.

A. The particulars of the physical configuration of the transmission and distribution system are important. The specific characteristics of the system configuration, such as, whether the distribution system is a centralized or a dispersed one, should be identified. Other such characteristics are whether the utility has a single city-gate or a multiple city-gate configuration, whether the utility has an integrated transmission and distribution system or a distribution-only operation, and whether the system is a multiple-pressure based or a single-pressure based operation.

Q. What are the specific physical characteristics of the Cascade's system?

A. The physical configuration of the Cascade' system is a dispersed / multiple city-gate, integrated transmission / distribution and multi pressure-based system.

Q. What was the source of the cost data analyzed in the Company's COSS?

A. All cost of service data have been extracted from the Company's total cost of service (i.e., total revenue requirement) and subsidiary schedules contained in this filing.

Q. How does the availability of data influence a COSS?

A. The structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region and the types of load data available. Cascade maintains detailed plant accounting records for many of its distribution-related facilities.

Q. How are the Cascade customer classes structured for purposes of the COSS?

A. The COSS evaluated seven customer classes: Residential Service (Tariff Schedules 502 and 503); General Commercial Service (Tariff Schedule 504) including Compressed Natural Gas (CNG) Service (Tariff Schedule 512) ; General Industrial Service (Tariff Schedule 505); Large Volume General Service (Tariff Schedule 511); Interruptible Service (Tariff Schedules 570 and 577); Distribution System Transportation Service (Tariff Schedule 663); and Special Contracts.

Q. How do state regulatory policies bear upon a utility's COSS?

A. State regulatory policies and requirements prescribe whether there is a particular approach historically used to establish utility rates in the state. Specifically, state regulations set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the particular cost allocation method utilized by the utility. For example, in a Washington Natural Gas (now Puget Sound

Energy) case, Docket No. UG-940814, the WUTC expressed a preference for the gas utility to utilize a costing methodology, Peak & Average, which allocates some fixed costs on the basis of annual use (or throughput) in order to reflect the proposition that a range of factors influence how gas transmission and distribution system costs are incurred and its significance in the cost study process. In its December 2016 Order in Docket Nos. UE-160228 and UG-160229 (*consolidated*), the WUTC instructed its staff to initiate a collaborative effort with the investor-owned Washington utilities and interested stakeholders to more clearly define the scope and expected outcomes for generic cost of service proceedings in an effort to establish greater clarity and uniformity in future cost of service studies.[1]

Q. Is the overall cost allocation approach utilized in Cascade's COSS consistent with that utilized in the prior rate case that you cited?

A. Yes. The overall allocation approach is similar to that adopted by the WUTC in Docket No. UG-940814.

Q. Please describe the Peak & Average methodology in greater detail as it has been applied in the Cascade COSS.

A. The Peak & Average ("P&A") methodology is a simplified version of the Average and Excess ("A&E") demand allocation methodology, also referred to as the "used and unused capacity" method. The A&E method allocates demand related costs to the classes of service on the basis of system and class load factor characteristics. Specifically, the portion of utility facilities and related expenses required to service the

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[1] *Wash. Utils. & Transp. Comm'n v. Avista Corp., dba Avista Utils.*, Docket Nos. UE-160228, *et al.*, Order 06, ¶116 (Dec. 15, 2016).

average load is allocated on the basis of each class' average demand and is derived by multiplying the total demand related costs by the utility's system load factor. The remaining demand related costs are allocated to the classes based on each class' excess or unused demand. The P&A methodology adopted in the referenced WUTC docket similarly weights the allocation of the utility's transmission and distribution system costs by the system load factor. The peak related portion of the P&A method is premised on the notion that investment in capacity is determined by the peak load(s) of the utility and therefore are allocated to each customer class in proportion to the demand coincident with the system peak of that customer class. The peak demand allocation process might focus on a single system peak, such as the highest daily demand occurring during the test period. Alternatively, it might include the average of several cold days, either consecutive or occurring over a period of several years, or it could be the expected contribution to the system peak under weather conditions for which the system was designed to serve, commonly referred to as a "design day." The peak demands utilized in the Cascade COSS are the respective design day demands for Cascade's firm sales classes, as developed in the Company's most recent Integrated Resource Plan ("IRP"). While the IRP does not reflect peak demands for the Interruptible Service, Distribution System Transportation Service and Special Contracts classes, the average of the measured daily demands during the system three-day peak in the test year for these classes were used to provide a peak related contribution for these non-core customer classes.

Q. Why did you choose to utilize Cascade's design day demand for the firm service classes rather than an actual peak day demand in the application of the P&A allocation method?

A. Use of a utility's design day demand is superior to using its actual peak day demand or a historical average of multiple peak day demands over time for purposes of deriving demand allocation factors for a number of reasons. These reasons include:

(1) A utility's gas system is designed, and consequently costs are incurred, to meet design day demand. In contrast, costs are not incurred on the basis of an average of peak demands.

(2) Design day demand is more consistent with the level of change in customer demands for gas during peak periods and is more closely related to the change in fixed plant investment over time.

(3) Design day demand provides more stable cost allocation results over time.

Q. Please explain why Cascade's design day demand best reflects the factors that actually cause costs to be incurred.

A. Cascade must consistently rely upon design day demand in the design of its own transmission and distribution facilities required to serve its firm service customers. More importantly, design day demand directly measures the gas demand requirements of the utility's firm service customers which create the need for Cascade to acquire resources, build facilities and incur millions of dollars in fixed costs on an ongoing basis. In my opinion, there is no better way to capture the true cost causative factors of Cascade's operations than to utilize its design peak day requirements within its cost of service studies.

Q. Please explain why use of design day demand provides more stable cost allocation results over time.

A. By definition, a utility's design day peak is as stable a determinant of planned capacity utilization as you can derive. If it were not a stable demand determinant, the design of a utility's gas system and supply portfolio would tend to vary and make the installation of facilities and acquisition of supply resources and capacity a much more difficult task. Therefore, use of design day demands provides a more stable basis than any of the other demand allocation factors available based on either actual peak day demand or the averaging of multiple peak days.

B. Transmission and Distribution Plant

Q. How were Transmission Mains allocated in the COSS?

A. Transmission mains were allocated to the firm and interruptible sales and transportation classes under the Peak & Average method described above, after deducting the transmission mains investment that was directly assigned to the Special Contracts class.

Q. How were Distribution Mains allocated in the COSS?

A. Distribution mains were allocated to the firm and interruptible sales and transportation classes under the Peak & Average method, after deducting the specific distribution mains investment that was directly assigned to the Special Contracts class. A special study was performed to determine the specific pipe size and type of intermediate pressure distribution main to which each of the special contract customers in the Interruptible Service class and the customers in the Distribution System Transportation Service class were attached. The respective customers' peak and average load characteristics were included in the allocation of that portion of the distribution mains investment for the tranches of mains of equal or greater pipe size than the main to which they were attached. The remaining firm sales service classes received a full allocation of all intermediate pressure mains regardless of pipe size or type. High pressure distribution mains were allocated to all classes, with the exception of the Special Contracts class, which received a direct assignment of these mains, as described earlier.

Q. Please describe the special studies conducted for purposes of allocating other distribution plant investment.

A. Regarding Cascade's major plant accounts, current cost factors were developed to allocate the following FERC plant accounts: Services – Account No. 380, Meters – Account 381, and House Regulators – Account No. 383. These cost factors reflect differences in the current unit equipment and installation costs that particular customer groups cause the Company to incur. For example, the cost of a 3/4-inch plastic service line that could serve a residential customer costs less, on a per unit basis, than the cost of a 4-inch steel service line to serve a larger industrial customer.

Q. What other noteworthy plant allocations have been made?

A. Miscellaneous Intangible Plant – Account 303, was segregated into customers, plant and throughput related categories and allocated accordingly based on a review of the investment elements in the account. For Industrial Measuring & Regulating ("M&R") Station Equipment – Account No. 385, an allocation of this plant to the various customer classes was facilitated by research of property records conducted by Cascade's Washington District Office personnel to identify specific equipment with individual customers. The remaining M&R equipment in Account No. 385 that could not be identified with individual customers were allocated to the classes based on the assignment of the identifiable M&R equipment costs.

Q. Please describe the method used to allocate the reserve for depreciation as well as depreciation expenses.

A. These items were allocated by function in proportion to their associated plant accounts.

C. Transmission and Distribution Operation and Maintenance Expenses

Q. How did the COSS allocate transmission and distribution related operation and maintenance ("O&M") expenses?

A: In general, these expenses were allocated on the basis of the cost allocation methods used for the Company's corresponding plant accounts. A utility's O&M expenses generally are thought to support the utility's corresponding plant in service accounts. Put differently, the existence of particular plant facilities necessitates the incurrence of cost, *i.e.*, expenses by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account. For example, Account No. 893, Meters and House Regulator Expenses, is allocated on the same basis as its corresponding plant accounts, Meters – Account 381 and House Regulators – Account 383. With the detailed analyses supporting the assignment or allocation of major plant in service components, where feasible, it was deemed appropriate to rely upon those results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

D. Customer Service and Administrative & General Expenses

Q. Please describe the costs included in customer service related O&M expenses and how these costs were treated in the COSS Study.

A. The category of customer related O&M expenses includes the following FERC accounts: Meter Reading – Account 902; Customer Records and Collections, including monthly billing postage and printing – Account 903; and Uncollectible Accounts – Account 904, involving the following Cascade Responsibility Centers: Customer Services (RC 4767100, RC 4767200); Credit and Collections (RC 4767000); Revenue Accounting (RC 4760700); Information Systems (RC 4767800); and the nine Washington Districts.

Meter Reading expenses were assigned to core or non-core customer groups based on an analysis of labor costs of field personnel involved in meter reading activities related to the respective customer groups and then allocated on a customer basis. Customer Records and Collections expenses were allocated to all classes using a composite allocation factor based on functions performed by the responsibility centers such as billing, revenue accounting, collection activity, and. Uncollectible Accounts expenses were assigned to the classes on the basis of uncollectible account write-offs.

Q How did the COSS allocate Administrative and General expenses?

A. Administrative and General ("A&G") expenses were allocated in relation to plant, O&M or labor expenses. Specifically, A&G expense Property Insurance – Account 924 was allocated on the basis of transmission and distribution plant, as were Rents – Account 931 and Maintenance of General Plant – Account 932. The following accounts were allocated on the basis of Cascade's labor expenses: A&G Salaries – Account 920, Office

Supplies and Expenses – Account 921, Outside Services – Account 923, Injuries and Damages – Account 925, and Pensions and Benefits – Account 926. Miscellaneous General Expense – Account 930 was allocated on the basis of transmission and distribution O&M. This is a reasonable approach to allocating A&G expenses.

Q. How did the COSS allocate taxes other than income taxes?

A. The study allocated all taxes, except for income taxes, in a manner which reflected the specific cost associated with the particular tax expense category. Generally, taxes can be cost classified on the basis of the tax assessment method established for each tax category, *i.e.*, payroll, property, or function. Typically, taxes of a utility other than income taxes can be grouped into the following categories: (1) labor; (2) plant; and (3) function, *e.g.*, Transmission, Distribution, Storage, etc. In the Cascade COSS, all non-income taxes were assigned to one of the above stated categories which were then used as a basis to establish an appropriate allocation factor for each tax account.

Q. How were income taxes allocated to each customer class?

A. Deferred income taxes and investment tax credits were allocated on a transmission and distribution plant basis. Current income taxes were allocated based on each individual class' revenue requirement.

E. Gas Supply O&M Expenses

Q. Please identify the costs included in gas supply related O&M expenses and how these costs were treated in the COSS?

A. The category of gas supply O&M expenses includes salaries and benefits of personnel in the following responsibility centers: Gas Supply Resource Planning (RC 4761100), Gas Supply (RC 4761200), Gas Control (RC 4763200), and a Management expense allocation from MDU (RC 4766000). The corresponding labor expenses were distributed among the three categories of Gas Planning, Gas Supply and Gas Control based on the time allocations reported by the personnel in these responsibility centers.

The Gas Planning function includes monthly/seasonal/annual gas resource planning; supply resource modeling and optimization; market intelligence gathering and analysis; IRP development; and Canadian / U.S. pipeline and storage operational, tolls / tariffs, and shipper related activities. The expenses in Other Gas Supply Expenses – Account 813 charged to this function were first segregated between core and non-core classes according to the assigned labor hours and then allocated among the core and non-core classes using a peak & average allocator.

The Gas Supply function includes gas supply procurement for core customers; balancing of core system supplies, including day-to-day storage activities; gas supply reporting, including commodity and closing price reporting; processing supplier invoices; updating and maintaining North American Energy Standards Board ("NAESB") contracts; and tracking import authorizations and North American Free Trade ("NAFTA") certificates. Types of activities relating to non-core customers include resolution of imbalances and communicating with non-core customers relating to imbalance "packing" or "drafting" that affects the overall system balance position. The expenses charged to this function in Account 813 were first segregated between core and non-core classes according to the assigned labor hours and then allocated among the core and non-core classes using sales or transportation volumes, respectively.

The Gas Control function entails the 24-hour daily monitoring and management of the flow of gas on the Cascade pipeline system in Washington. This is accomplished by gas control personnel through electronic monitoring of various points on the system via SCADA and Metretek measurement equipment. The SCADA sites are located at town border stations throughout the Cascade system and at some Special Contract customer locations. Metretek monitoring equipment is located at non-core customer locations for classes 570/577, 663 and 900. The expenses charged to this function in Distribution Load Dispatching – Account 871 were first segregated between core and non-core classes according to a recent twelve-month study of recorded actionable items triggered by information provided by the SCADA and Metretek sites and the related labor hours, and then allocated among the core and non-core classes using sales or transportation volumes, respectively.

F. Cascade's Cost of Service Study Results

Q. Have you prepared a summary of Cascade's COSS results?

A. Yes. Exhibit No. __ (RJA-2) summarized the results of Cascade's COSS. In particular, the exhibit presents the resulting allocation by customer class of Cascade's proposed revenue requirement based strictly on the results of the computations included in the COSS.

Q. Please compare the resulting COSS results to the current rates and associated non-gas revenues for each of Cascade's customer classes**.**

A. Exhibit No. __ (RJA-2), page 2, line 27 presents the total COSS-based rate schedule revenue requirement for each of Cascade's customer classes at the proposed system rate of return. Line 7, page 1, of this Exhibit presents Test Year margin revenues by customer class under Cascade's current rates, net of gas costs, other operating revenues, miscellaneous charges, and revenue taxes. By comparing these two sets of revenues, one can see the extent to which Cascade's current rates and non-gas revenues are reflective of COSS. The revenue-to-cost ratios on line 45, page 2, of this exhibit portray the relative difference between these two revenue amounts for each class. A revenue-to-cost ratio of less than 1.00 means that the current rates and revenues of the particular customer class are below its indicated COSS (*i.e.*, Customer Class 502/503 and 663), while a revenue-to-cost ratio of greater than 1.00 means that the rates and revenues of the customer class are above its indicated COSS (*e.g.*, Special Contract Class 900). These results provide cost guidelines for use in evaluating a utility's class revenue levels and rate structures. I will describe later in my testimony how these results were used to assign Cascade's proposed revenue increase to its customer classes.

Q. Please describe the information presented in Exhibit No. __ (RJA-3).

A. The COSS summarized the costs allocated to the customer classes on a functionalized (*i.e.* by production (gas supply related), transmission, and distribution), and classified (*i.e.* by demand, customer and commodity) basis. Of particular interest are the customer related costs. Exhibit No. __ (RJA-3) provides a summary of the functionalized and classified costs, and shows these on a unit cost basis. These results were used as a guide in developing the proposed monthly Basic Service Charge levels by tariff schedule, as discussed later in my testimony.

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design you have relied upon as the basis for Cascade's rate design proposals.

A. A number of rate design principles or objectives find broad acceptance in utility regulatory and policy literature. These include:

1. Efficiency;
2. Cost of Service;
3. Value of Service;
4. Stability;
5. Non-Discrimination;
6. Administrative Simplicity; and
7. Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates. Each of these principles plays an important role in analyzing the rate design proposals of Cascade.

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the gas utility system is designed and constructed to meet the design day requirements of customers using the most economic equipment and technology consistent with design standards.

Q. Please discuss the cost of service and value of service principles.

A. These principles each relate to designing rates that recover the utility's total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service. This principle puts the concept of SAC, discussed earlier, into practice and is particularly relevant for Cascade because of the competitive supply alternatives that cap rates under its special contracts.

Q. Please discuss the principle of stability.

A. The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design.

Q. Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that "equals should be treated equally" and vertical equity requires that "unequals should be treated unequally." Specifically, these principles of equity require that where cost of service is equal—rates should be equal and, where costs are different—rates should be different. In this case, this principle is an important requirement that supports Cascade's proposed use of a single monthly Basic Service Charge for all customers within certain of its tariff schedules.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. Please discuss the principle of the balanced budget.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that I previously discussed from the perspective of customer rates.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. For example, as noted above, there are tensions between cost and value of service principles.

Q. Please describe the conflict between marginal cost price signals and the recovery of the utility's revenue requirement.

A. The conflict between proper price signals based on marginal cost and the balanced budget principle arises because marginal cost is below average cost due to economies of scale. Where fixed delivery service costs do not vary with the volume of gas sales, marginal costs for delivery equal zero. Marginal customer costs equal the additional cost of the customer accessing the entire gas delivery system. Marginal cost tends to be either above or below average cost in both the short run and the long run. This means that marginal cost-based pricing will produce either too much or too little revenue to support the utility's total revenue requirement. This suggests that efficient price signals may require a multi-part tariff designed to meet the utility's revenue requirements while sending marginal cost price signals related to gas consumption decisions. Properly designed, a multi-part tariff may include elements such as access charges, facilities charges, demand charges, consumption charges, and the potential for revenue credits.

In the case of a local distribution company ("LDC") such as Cascade, for residential and small commercial customers, the combination of scale economies and class homogeneity may permit the use of a single fixed monthly charge that meets all of the requirements for an efficient rate that recovers the utility's revenue requirement that is derived on an embedded cost basis. For larger customers, a combination of these elements permit proper price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For larger customers, the added complexity of a demand charge may not be a concern. Further, for the largest customers, the cost of metering is customer-specific and each customer creates its own unique requirements for gas distribution service based on factors such as distance from the utility's city gate, pressure requirements, and contract demand levels.

Q. Are there other potential conflicts?

A. Yes. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. Please summarize Bonbright's three primary criteria for sound rate design.

A. Bonbright identifies the three primary criteria for sound rate design as follows:

- Capital Attraction
- Consumer Rationing
- Fairness to Ratepayers

These three criteria are basically a subset of the list of principles above and serve to emphasize fundamental considerations in designing public utility rates. Capital attraction is a combination of an equitable rate of return on rate base and the reasonable opportunity to earn the allowed rate of return. Consumer rationing requires that rates discourage wasteful use and promote all economically efficient use. Fairness to ratepayers reflects avoidance of undue discrimination and equity principles.

Q. How are these principles translated into the design of retail gas rates?

A. The process of developing rates within the context of these principles and conflicts requires a detailed understanding of all the factors that impact rate design. These factors include:

1. System cost characteristics such as established in the COSS required by the WUTC, or embedded customer, demand, and commodity related costs by type of service;
2. Customer load characteristics such as peak demand, load factor, seasonality of loads, and quality of service;
3. Market considerations such as elasticity of demand, competitive fuel prices, end-use load characteristics, and LDC bypass alternatives; and

4. Other considerations such as the value of service ceiling/marginal cost floor, unique customer requirements, areas of underutilized facilities, opportunities to offer new services and the status of competitive market development.

In addition, the development of rates must consider existing rates and the customer impact from modifications to the rates. In each case, a rate design seeks to recover the authorized level of revenue based on the billing determinants expected to occur during the test period used to develop the rates.

The overall rate design process, which includes both the apportionment of the revenues to be recovered among customer classes and the determination of rate structures within customer classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter into the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process has to be, in part, influenced by judgmental evaluations.

V. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Cascade's proposed revenue increase of $5.9 million to its customer classes.

A. As just described, the apportionment of revenues among customer classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for Cascade's customer classes

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of Cascade's interclass revenue proposal?

A. Yes. Using Cascade's proposed revenue increase, and the results of its COSS, I evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with Cascade personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The first and benchmark option that I evaluated under Cascade's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This decision was also made in consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

The second option I considered was assigning the increase in revenues to Cascade's customer classes based on an equal percentage basis of its current base (non-gas) revenues. By definition, this option resulted in each customer class receiving an increase in revenues. However, when this option was evaluated against the COSS Study results (as measured by changes in the revenue-to-cost ratio for each customer class); there was no movement towards cost for most of Cascade's customer classes (*i.e.*, there was no convergence of the resulting revenue-to-cost ratios towards unity or 1.00). While this option also was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provides further guidance to develop Cascade's class revenue proposal.

Q. What was the result of this process?

A. After further discussions with Cascade, I concluded that the appropriate interclass revenue proposal would consist of an adjustment to the present revenue level in Cascade's Residential Service class (Tariff Schedules 502 and 503), the Interruptible Service class (Tariff Schedules 570 and 577) and the Distribution System Transportation Service (Tariff Schedule 663). In the case of the Residential Service class, the revenue adjustment insures their proposed rates will move class revenues closer to the COSS for the class. Not only was the Residential Service class below unity (< 1.00 revenue-to-cost ratio) in the COSS results, it produced a minimal class rate of return ("ROR") at 0.07 . While the Interruptible Service class' revenue-to-cost ratio was slightly above unity at current rates (1.01), and the Distribution System Transportation Service revenue-to-cost ratio slightly less than unity (0.98), the proposed revenue adjustments bring these two classes closer in alignment with their remaining commercial /industrial class counterparts.

The COSS results for the remaining customer classes indicate their respective class rates of return are above the system average rate of return at both the Company's current and proposed ROR levels. While this would suggest the need for revenue decreases in order to move many of these customer classes closer to cost (*i.e.*, convergence of the resulting revenue-to-cost ratios towards unity or 1.00), the resulting customer impact implications for the Residential Service class has led me to conclude, in consultation with the Company, to refrain from revenue reductions for the remaining customer classes.

In summary, this preferred revenue allocation approach resulted in reasonable movement of the Residential class revenue-to-cost ratio toward unity or 1.00. That result, a revenue-to-cost ratio of 0.93, is reflected in Exhibit No. __ (RJA-2), page 2, on Line 47. From a class cost of service standpoint, this type of class movement, and reduction in the existing class rate subsidies, is desirable.

VI. CASCADE'S RATE DESIGN PROPOSALS

Q. Please summarize the rate design changes Cascade has proposed in this rate proceeding.

A. I will present the specific rate design changes and supporting rationale for Cascade's proposals. Cascade has proposed the following rate design changes to its current tariff schedules:

- For customers served under Residential Service class (Tariff Schedule 503), General Commercial Service class (Tariff Schedule 504); General Industrial Service (Tariff Schedule 505); Large Volume General Service (Tariff Schedule 511); Interruptible Service (Tariff Schedules 570 and 577); and Distribution System Transportation Service (Tariff Schedule 663), Cascade proposes to adjust the monthly Basic Service Charges to better reflect the underlying costs of providing basic customer service.
- Cascade is proposing to eliminate the Tariff Schedule 502, Building Construction Temporary Heating and Dry-Out Service, and merge those customers into the Residential Service class (Tariff Schedule 502).

- Increasing the Demand Rate in the Distribution System Transportation Service (Tariff Schedule 663) to better reflect the underlying unit demand costs associated with this customer class.

Q. Please describe the changes to the monthly Customer Charge levels for Tariff Schedule 505, Schedule 511, Schedule 570, and Schedule 577 .

A. The proposed monthly Basic Service Charge for Schedule 505 is $75.00, an increase of $27.00, which raises the charge to approximately 59 percent of the upper range of the unit customer-related costs for the class, as indicated in the Unit Cost Report, Exhibit No. __ (RJA-3). The proposed monthly Basic Service Charge for Schedule 511 is $200.00, which raises the charge to within approximately 50 percent of the upper range of the indicated unit customer-related cost for the class. The proposed monthly Basic Service Charges for Schedules 570 and 577 are $500.00, which raises these charges to within 45 percent of the upper range of the indicated unit customer-related cost for the class. These increases to the Basic Service Charges will provide significant improvement in the recovery of the fixed customer-related costs via fixed charges. With the exception of Schedules 570 / 577, to offset the foregoing increases to the Basic Service Charges, all blocks of the volumetric rates in the respective tariff schedules were reduced ratably based on the margin revenue in each block.

Q. Is Cascade proposing to increase the Basic Service Charge for any of the remaining tariff schedules?

A. Yes. Cascade proposes to increase the Basic Service Charges for the Residential Service Schedule 503 to $6.00 from its current $4.00 level, and the General Commercial Service Schedule 504 to $15.00 from its current $10.00 monthly charge level. At this level, the

Basic Service Charge for these two classes of service will recover more of the monthly customer-related O&M (meter reading, billing and uncollectibles), and return of and on the meter and service line plant, as indicated by the COSS Study.

Q. Please describe the proposed changes to the Distribution System Transportation Service (Tariff Schedule 663).

A. The Customer Service Charge in Tariff Schedule 663 will be increased under Cascade's proposal to $750.00 from the current level of $500.00, which is approximately 53 percent of the level of customer-related cost for this customer class as shown in the Unit Cost Report, Exhibit No. __ (RJA-3). The current System Balancing Charge of $0.0004 per therm of gas transported will remain unchanged. The revenue from the System Balancing Charge will be credited to the PGA, thus reimbursing sales customers for the use of a portion of the Jackson Prairie storage resource for balancing the net differences between the transportation customers' daily transportation deliveries and daily gas usage. The System Balancing charge was derived from a study of Cascade's net daily system imbalance activity over the past three years. The System Balancing Charge will also apply to the transported volumes for the Special Contract customers.

Finally, the current Contract Demand ("CD") Charge in Schedule 663 of $0.20 per CD therms per month will be raised to $0.22, which will recover approximately 86 percent of the unit demand-related costs for this customer class. All blocks of the volumetric Delivery Charge in Schedule 663 will be ratably increased to collect the remainder of the proposed revenue increase to this Tariff Schedule.

Q. Have you provided an exhibit that depicts the proposed rates for all classes of service?

A. Yes. Exhibit No. __ (RJA-4) shows the derivation of each rate component for each of Cascade's tariff schedules.

Q. What is the impact of the foregoing proposed increases to fixed charges on the recovery of Cascade's fixed delivery service costs?

A. The proposed increases to the various Customer Service Charges and the proposed $.02 increase to the CD Charge in Schedule 663 will result in an overall increase of $7.2 million of fixed cost recovery in fixed charges or 28 percent of Cascade's total rate schedule generated non-gas revenue requirement, leaving $71.4 million of fixed transmission and distribution costs to be recovered via the volumetric Delivery Charges.

Q. Has a revenue proof been prepared to show that Cascade's proposed rates generate the total distribution revenue and total revenue increase it has proposed in this proceeding (*i.e.* its total non-gas revenue)?

A. Yes. Cascade witness Maryalice Rosales presents Cascade's revenue proof for the Test Year.

VII. CUSTOMER BILL IMPACTS

Q. Please describe the bill impacts for residential customers under Cascade's rate design proposal.

A. The monthly and annual bill impacts for a typical residential customer using 653 therms per year is shown on Exhibit No. __ (RJA-5) The average monthly increase for this residential customer under the Company's proposed rate design is $2.09 or 4.41 percent. Monthly residential bill impacts over a range of usage are depicted on page 1 of Exhibit No. __ (RJA-6).

Q. Have you prepared bill comparisons for Cascade's other non-residential tariff schedules?

A. Yes. Exhibit __ (RJA-6) also presents bill comparisons for Cascade's non-residential service tariff schedules at varying monthly levels of gas usage, with the exception of Schedule 663. The average cost per therm of gas transported for these customers will uniquely vary based on the relationship of their level of monthly transportation volumes to their individual contract demands; in other words, the higher the load factor experienced by the individual Schedule 663 customers – the lower will be their average cost per therm. Average monthly bill increases for Schedule 663 customers under Cascade's proposed changes to the rate components of the Tariff Schedule range from a low of 3.0 percent for the largest customers to 30 percent or more for a few customers with low load factors and 30,000 therms or less of annual consumption.

VIII. DETERMINATION OF ALLOCATED GAS RESOURCE DEMAND COSTS

Q. What is the purpose of this section of your testimony?

A. This section of my testimony describes the manner in which the Company plans for and utilizes the gas transportation and storage capacity that is needed to serve its natural gas customers. I will provide a recommendation as to the allocation of pipeline capacity and storage costs for use in Cascade's PGA filings.

Q. Please describe what drives Cascade's decisions regarding the use of pipeline capacity.

A. Most of Cascade's natural gas sales customers are firm customers as opposed to interruptible customers. Firm customers expect to receive gas at all times, particularly during extremely cold weather. Demand for natural gas from Cascade's firm customers is at its highest during cold weather. However, the cold weather increases the demand of other interstate pipeline customers, thus reducing the availability of contracted but unused pipeline capacity.

Given Cascade's obligation to serve its firm customers, it is the expected customer demand, and in particular the shape of that demand, that drives Cascade to plan for and use pipeline capacity. As more fully described in the Company's 2016 IRP, Cascade seeks the least cost mix of available resources that can meet its design-day peak standard. Often, due to lack of additional storage or other peaking resources, the only available incremental resource to ensure Cascade's ability to meet its design day standard is year-round pipeline capacity.

Q. How does Cascade determine its use of pipeline capacity?

A. The process for determining the need for pipeline capacity can be summarized in the six-step process described below. The six steps reflect a logical progression in identifying why and when capacity is needed, and thus give guidance as to how to allocate the related costs.

Q. Please identify the steps and how they can guide pipeline capacity resource cost allocation.

A. **<u>Step 1:</u>** One must consider the average summer demand or sales volume level. This must be served by flowing gas supply using year-round pipeline capacity because, other than for load balancing, storage and peaking resources are not available in the summer.

Cascade's normalized average daily sales volume in the summer months during the 12 months ended December 2016 was approximately 29,975 Dth/day. Thus, average summer sales volumes require pipeline capacity of 29,975 Dth/day. Since this capacity is only available on a year-round basis and will be used to serve winter sales volumes as well (Step 2), it is reasonable to allocate the cost of this capacity to Annual Sales Volumes.

Step 2: In order to have sufficient volumes in storage to serve the winter sales volumes, storage injections must be made using flowing gas and year-round pipeline capacity. Average summer injection requirements for Jackson Prairie and Plymouth LNG are 8,259 Dth/day. Cascade could schedule its injection requirements around its customer requirements and operate all summer long with 8,259 Dth/day of pipeline capacity. Because this capacity is needed specifically to fill storage, which is in turn used to serve winter sales volumes, it is reasonable to allocate the costs of this capacity to Winter Sales Volumes. This capacity is also available to flow additional gas to serve winter sales volumes after the summer injection period (Step 3).

Step 3: Before determining the need for additional pipeline capacity to serve winter demand, Cascade considers the average availability of storage withdrawals from Jackson Prairie that use Northwest Pipeline TF-2 capacity and thus do not require the use of year-round pipeline capacity. Average Daily winter withdrawals from Jackson Prairie storage average approximately 1,371 Dth/day. The TF-2 capacity utilized by Jackson Prairie withdrawals would reasonably be allocated partially to Winter Sales Volumes, Design Peak Volumes and of course, system load balancing.

Step 4: Winter average daily sales volumes are 98,491 Dth/day. These requirements are met with the capacity acquired in Steps 1, 2 and 3, thus leaving an average winter sales demand of 58,886 Dth/day (98,491 minus 1,371 minus 8,259 minus 29,975) to be fulfilled with additional year-round pipeline capacity. It is reasonable to allocate the costs of this capacity to Winter Sales Volumes.

Step 5: Cascade considers its Design Peak Sales Requirement and the deliverability of all of its storage and peaking resources that have not already been considered in use on the average winter day. Cascade's estimated design peak requirement for the 12 months ended December 2016 was approximately 262,836 Dth/day. Cascade's peaking and storage resources provide, at maximum deliverability, a total of 78,299 Dth/day (9,577 from Jackson Prairie and 68,722 from Plymouth LNG). However, Cascade has already relied on 1,371 Dth/day from Jackson Prairie on an average winter day in Step 3, thus incremental storage and peaking provide a resource of 76,928 Dth/day (78,299 minus 1,371). It is reasonable that the costs of the various resources that provide this incremental deliverability should be allocated based on their use to serve the design peak requirements of the system.

Step 6: The design peak demand is not yet met, and no additional gas storage or peaking resources are available in a cost effective manner. Cascade thus must use additional year-round pipeline capacity of 180,827 Dth/day (262,836 minus 29,975 minus 8,259 minus 58,886 minus 78,299 plus an approximate reserve of 93,410) to make up the shortfall. Because this last increment of pipeline capacity is required only to serve the design peak day requirements of the customer demand, it is reasonable to allocate the cost of this capacity based on the contribution of various customer classes to design peak day demand. Exhibit No. __ (RJA-7), pages 2 and 3, illustrates the six steps described above in both tabular and graphical format, respectively.

Q. What is your overall recommendation as to the allocation of year-round pipeline capacity, storage, peaking and redelivery capacity (TF-2) costs?

A. As summarized in the table on page 2 of Exhibit No. __ (RJA-7), showing the six step process, I recommend that year-round pipeline capacity costs should be allocated within the PGA as 9.9 percent to Annual Sales Volumes, 19.4 percent to Winter Sales Volumes and 70.7 percent to Design Peak Volumes. I recommend that the 80 percent of Jackson Prairie and its related TF-2 capacity that is not allocated to system balancing be allocated in the PGA as follows: 11.3 percent to Winter Sales and 68.7 percent to Design Peak Day.

Q. What are the resulting unit demand cost rates for the various sales service classes in the PGA?

A. The result of the computations to determine the class-by-class unit demand cost rates that result from the foregoing allocation of pipeline, storage and peaking capacity are shown on page 1 of Exhibit No. __ (RJA-7).

Q. Does this conclude your direct testimony?

A. Yes.