

**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**

**JULY 31, 2017**

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## **I. INTRODUCTION AND SUMMARY**

1 **Q. Please state your name and business address.**

2 A. My name is Ronald J. Amen and my business address is 17806 NE 109<sup>th</sup> Court,  
3 Redmond, Washington 98052.

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

5 A. I am appearing on behalf of Cascade Natural Gas Corporation (“Cascade” or the  
6 “Company”).

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

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

11 **Q. Please describe the firm of Black & Veatch.**

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

19 Black & Veatch has extensive experience in all aspects of the North American  
20 natural gas industry, including utility costing and pricing, gas supply and transportation  
21 planning, competitive market analysis, and regulatory practices and policies gained  
22 through management and operating responsibilities at gas distribution, pipeline, and

1 other energy-related companies, and through a wide variety of client assignments.  
2 Black & Veatch has assisted numerous gas distribution companies located in the U.S.  
3 and Canada.

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

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

18 **Q. Have you testified previously before the Washington Utilities and Transportation**  
19 **Commission (“Commission” or “WUTC”)?**

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

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

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

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

10 **Q. Please summarize your testimony.**

11 A. In my testimony I present Cascade’s Cost of Service Study (“COSS”) and discuss its  
12 results, and I present the various rate design proposals filed by Cascade in this  
13 proceeding.

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

- 16 • Theoretical Principles of Cost Allocation
- 17 • Cascade’s COSS
- 18 • Principles of Sound Rate Design
- 19 • Determination of Proposed Class Revenues
- 20 • Cascade’s Rate Design Proposals
- 21 • Residential & Non-Residential Class Bill Impacts
- 22 • Determination of Gas Resource Demand Costs by Customer Class for Use in  
23 Cascade’s PGA Filings

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

2 A. The following exhibits accompany my testimony.

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

II. **THEORETICAL PRINCIPLES OF COST ALLOCATION**

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

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

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

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

8 Embedded cost studies analyze the costs for a test period based on either the  
9 book value of accounting costs (an historical period) or the estimated book value of  
10 costs for a forecast test year or some combination of historical and future costs.

11 Where a forecast test year is used, the costs and revenues are typically derived from  
12 budgets prepared as part of the utility’s financial plan. Typically, embedded cost  
13 studies are used to allocate the revenue requirement between jurisdictions, classes,  
14 and between customers within a class.

15 Marginal cost studies can reflect actually incurred costs but often rely on  
16 estimates of the expected changes in cost associated with changes in utility service.  
17 Marginal cost studies are forward-looking to the extent permitted by available data.  
18 Marginal cost studies may be particularly useful for rate design and can also be used  
19 as a guide to determine how a utility’s total revenue requirement should be allocated  
20 to its classes of service. Where it is important to send appropriate price signals  
21 associated with additional energy consumption by customers, an understanding of  
22 marginal cost may be useful. For a gas utility, detailed studies are not required to  
23 assess the impact of additional consumption by existing customers since the delivery

1 system is built for design day requirements and energy conservation has reduced  
2 those requirements for most customers. Where new customers are added to the  
3 system, growth may increase design day requirements above an amount that existing  
4 facilities can serve. The principal factors driving new main investment are customer  
5 growth and the replacement of aging pipeline infrastructure such as bare steel and  
6 cast iron mains to provide safe and reliable service for customers.

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

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

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



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

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

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

21           However, the existence of common costs makes any allocation of costs  
22 problematic from a strict economic perspective. This is theoretically true for any of  
23 the various utility costing methods that may be used to allocate costs. Theoretical

1 economists have developed the theory of subsidy-free prices to evaluate traditional  
2 regulatory cost allocations. Prices are said to be subsidy-free so long as the price  
3 exceeds marginal cost, but is less than stand-alone costs (“SAC”). The logic for this  
4 concept is that if customers’ prices exceed marginal cost, those customers make a  
5 contribution to the fixed costs of the utility. All other customers benefit from this  
6 contribution to fixed costs because it reduces the cost they are required to bear.  
7 Prices must be below the SAC because the customer would not be willing to  
8 participate in the service offering if prices exceed SAC.

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

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

19 A. As noted above, the practical reality of regulation often requires that common costs  
20 be allocated among jurisdictions, classes of service, rate schedules, and customers  
21 within rate schedules. The key to a reasonable cost allocation is an understanding of  
22 *cost causation*. Cost causation, as alluded to earlier, addresses the need to identify  
23 which customer or group of customers causes the utility to incur particular types of

1 costs. To answer this question, it is necessary to establish a linkage between a Local  
2 Distribution Company's ("LDC's") customers and the particular costs incurred by the  
3 utility in serving those customers.

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

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

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

20 Customer related costs are incurred to attach a customer to the distribution  
21 system, meter any gas usage and maintain the customer's account. Customer costs are  
22 a function of the number of customers served and continue to be incurred whether or  
23 not the customer uses any gas. They may include capital costs associated with

1 minimum size distribution mains, services, meters, regulators and customer service  
2 and accounting expenses.

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

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

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

1 some classes such as the largest customers, the meter cost may be unique for each  
2 customer.

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

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

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

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

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

20 A. When direct assignment is not readily apparent from the description of the costs  
21 recorded in the various utility plant and expense accounts, then further analysis may be  
22 conducted to derive an appropriate basis for cost allocation. For example, in evaluating  
23 the costs charged to certain operating or administrative expense accounts, it is customary

1 to assess the underlying activities, the related services provided, and for whose benefit  
2 the services were performed.

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

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

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

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

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

21 A. Yes. A special study was performed to determine the specific transmission and  
22 distribution mains, as well as the customer service lines, that were constructed to serve  
23 Cascade's Special Contract customers. The plant costs related to these facilities were

1 directly assigned to the Special Contract class in the COSS. The Company's  
2 Geographic Information System ("GIS") was queried to research the various pipeline  
3 pathways from system regulator stations to the customers' service addresses along with  
4 the related pipeline sizes, material types, and pressure classification. Historical plant  
5 records such as work orders, distribution line reports, facilities installation diagrams,  
6 statistical data sheets, and gas service record cards were reviewed to obtain the  
7 necessary facilities data and construction cost information to complete the direct  
8 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

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

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

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

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

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

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

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

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

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



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

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

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

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

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

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

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

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

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

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

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

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

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

17 A. The Peak & Average (“P&A”) methodology is a simplified version of the Average and  
18 Excess (“A&E”) demand allocation methodology, also referred to as the "used and  
19 unused capacity" method. The A&E method allocates demand related costs to the  
20 classes of service on the basis of system and class load factor characteristics.

21 Specifically, the portion of utility facilities and related expenses required to service the

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<sup>1</sup> *Wash. Utils. & Transp. Comm’n v. Avista Corp., dba Avista Utils.*, Docket Nos. UE-160228, *et al.*, Order 06, ¶116 (Dec. 15, 2016).

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

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

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

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

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

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

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

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

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

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

**B. Transmission and Distribution Plant**

10 **Q. How were Transmission Mains allocated in the COSS?**

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

14 **Q. How were Distribution Mains allocated in the COSS?**

15 A. Distribution mains were allocated to the firm and interruptible sales and transportation  
16 classes under the Peak & Average method, after deducting the specific distribution  
17 mains investment that was directly assigned to the Special Contracts class. A special  
18 study was performed to determine the specific pipe size and type of intermediate  
19 pressure distribution main to which each of the special contract customers in the  
20 Interruptible Service class and the customers in the Distribution System Transportation  
21 Service class were attached. The respective customers' peak and average load  
22 characteristics were included in the allocation of that portion of the distribution mains

1 investment for the tranches of mains of equal or greater pipe size than the main to which  
2 they were attached. The remaining firm sales service classes received a full allocation of  
3 all intermediate pressure mains regardless of pipe size or type. High pressure  
4 distribution mains were allocated to all classes, with the exception of the Special  
5 Contracts class, which received a direct assignment of these mains, as described earlier.

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

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

15 **Q. What other noteworthy plant allocations have been made?**

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

1 identified with individual customers were allocated to the classes based on the  
2 assignment of the identifiable M&R equipment costs.

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

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

**C. Transmission and Distribution Operation and Maintenance Expenses**

6 **Q. How did the COSS allocate transmission and distribution related operation and**  
7 **maintenance (“O&M”) expenses?**

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

**D. Customer Service and Administrative & General Expenses**

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

3 A. The category of customer related O&M expenses includes the following FERC  
4 accounts: Meter Reading – Account 902; Customer Records and Collections,  
5 including monthly billing postage and printing – Account 903; and Uncollectible  
6 Accounts – Account 904, involving the following Cascade Responsibility Centers:  
7 Customer Services (RC 4767100, RC 4767200); Credit and Collections (RC  
8 4767000); Revenue Accounting (RC 4760700); Information Systems (RC 4767800);  
9 and the nine Washington Districts.

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

18 **Q How did the COSS allocate Administrative and General expenses?**

19 A. Administrative and General (“A&G”) expenses were allocated in relation to plant, O&M  
20 or labor expenses. Specifically, A&G expense Property Insurance – Account 924 was  
21 allocated on the basis of transmission and distribution plant, as were Rents – Account  
22 931 and Maintenance of General Plant – Account 932. The following accounts were  
23 allocated on the basis of Cascade’s labor expenses: A&G Salaries – Account 920, Office



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

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

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

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

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

**E. Gas Supply O&M Expenses**

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

20 A. The category of gas supply O&M expenses includes salaries and benefits of personnel  
21 in the following responsibility centers: Gas Supply Resource Planning (RC 4761100),  
22 Gas Supply (RC 4761200), Gas Control (RC 4763200), and a Management expense

1 allocation from MDU (RC 4766000). The corresponding labor expenses were  
2 distributed among the three categories of Gas Planning, Gas Supply and Gas Control  
3 based on the time allocations reported by the personnel in these responsibility centers.

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

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

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

**F. Cascade’s Cost of Service Study Results**

13 **Q. Have you prepared a summary of Cascade’s COSS results?**

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

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

20 A. Exhibit No. \_\_ (RJA-2), page 2, line 27 presents the total COSS-based rate schedule  
21 revenue requirement for each of Cascade’s customer classes at the proposed system  
22 rate of return. Line 7, page 1, of this Exhibit presents Test Year margin revenues by

1 customer class under Cascade's current rates, net of gas costs, other operating  
2 revenues, miscellaneous charges, and revenue taxes. By comparing these two sets of  
3 revenues, one can see the extent to which Cascade's current rates and non-gas  
4 revenues are reflective of COSS. The revenue-to-cost ratios on line 45, page 2, of  
5 this exhibit portray the relative difference between these two revenue amounts for  
6 each class. A revenue-to-cost ratio of less than 1.00 means that the current rates and  
7 revenues of the particular customer class are below its indicated COSS (*i.e.*,  
8 Customer Class 502/503 and 663), while a revenue-to-cost ratio of greater than 1.00  
9 means that the rates and revenues of the customer class are above its indicated COSS  
10 (*e.g.*, Special Contract Class 900). These results provide cost guidelines for use in  
11 evaluating a utility's class revenue levels and rate structures. I will describe later in  
12 my testimony how these results were used to assign Cascade's proposed revenue  
13 increase to its customer classes.

14 **Q. Please describe the information presented in Exhibit No. \_\_ (RJA-3).**

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

#### IV. PRINCIPLES OF SOUND RATE DESIGN

1 **Q. Please identify the principles of rate design you have relied upon as the basis for**  
2 **Cascade’s rate design proposals.**

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

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

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

16 **Q. Please discuss the principle of efficiency.**

17 A. The principle of efficiency broadly incorporates both economic and technical  
18 efficiency. As such, this principle has both a pricing dimension and an engineering  
19 dimension. Economically efficient pricing promotes good decision-making by gas  
20 producers and consumers, fosters efficient expansion of delivery capacity, results in  
21 efficient capital investment in customer facilities, and facilitates the efficient use of  
22 existing gas pipeline, storage, transmission, and distribution resources. The  
23 efficiency principle benefits stakeholders by creating outcomes for regulation

1 consistent with the long-run benefits of competition while permitting the economies  
2 of scale consistent with the best cost of service. Technical efficiency means that the  
3 development of the gas utility system is designed and constructed to meet the design  
4 day requirements of customers using the most economic equipment and technology  
5 consistent with design standards.

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

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

16 **Q. Please discuss the principle of stability.**

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

20 **Q. Please discuss the concept of non-discrimination.**

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

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

14   **Q.    Please discuss the principle of administrative simplicity.**

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

20   **Q.    Please discuss the principle of the balanced budget.**

21    A.    This principle permits the utility a reasonable opportunity to recover its allowed  
22          revenue requirement based on the cost of service. Proper design of utility rates is a  
23          necessary condition to enable an effective opportunity to recover the cost of providing

1 service included in the revenue authorized by the regulatory authority. This principle  
2 is very similar to the stability objective that I previously discussed from the  
3 perspective of customer rates.

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

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

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

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



1 decisions. Properly designed, a multi-part tariff may include elements such as access  
2 charges, facilities charges, demand charges, consumption charges, and the potential  
3 for revenue credits.

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

18 **Q. Are there other potential conflicts?**

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

23 **Q. Please summarize Bonbright’s three primary criteria for sound rate design.**

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

- 2 • Capital Attraction
- 3 • Consumer Rationing
- 4 • Fairness to Ratepayers

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

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

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

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

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

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

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

#### V. DETERMINATION OF PROPOSED CLASS REVENUES

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

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

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

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

15 The second option I considered was assigning the increase in revenues to  
16 Cascade's customer classes based on an equal percentage basis of its current base (non-  
17 gas) revenues. By definition, this option resulted in each customer class receiving an  
18 increase in revenues. However, when this option was evaluated against the COSS Study  
19 results (as measured by changes in the revenue-to-cost ratio for each customer class);  
20 there was no movement towards cost for most of Cascade's customer classes (*i.e.*, there  
21 was no convergence of the resulting revenue-to-cost ratios towards unity or 1.00).

22 While this option also was not the preferred solution to the interclass revenue issue,

1 together with the fully cost-based option, it defined a range of results that provides  
2 further guidance to develop Cascade's class revenue proposal.

3 **Q. What was the result of this process?**

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

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

1 conclude, in consultation with the Company, to refrain from revenue reductions for  
2 the remaining customer classes.

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

## VI. CASCADE'S RATE DESIGN PROPOSALS

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

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

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

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

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

6     A.     The proposed monthly Basic Service Charge for Schedule 505 is \$75.00, an increase of  
7             \$27.00, which raises the charge to approximately 59 percent of the upper range of the  
8             unit customer-related costs for the class, as indicated in the Unit Cost Report, Exhibit  
9             No. \_\_ (RJA-3). The proposed monthly Basic Service Charge for Schedule 511 is  
10            \$200.00, which raises the charge to within approximately 50 percent of the upper range  
11            of the indicated unit customer-related cost for the class. The proposed monthly Basic  
12            Service Charges for Schedules 570 and 577 are \$500.00, which raises these charges to  
13            within 45 percent of the upper range of the indicated unit customer-related cost for the  
14            class. These increases to the Basic Service Charges will provide significant  
15            improvement in the recovery of the fixed customer-related costs via fixed charges. With  
16            the exception of Schedules 570 / 577, to offset the foregoing increases to the Basic  
17            Service Charges, all blocks of the volumetric rates in the respective tariff schedules were  
18            reduced ratably based on the margin revenue in each block.

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

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

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

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

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

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

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



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

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

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

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

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

## **VII. CUSTOMER BILL IMPACTS**

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

17 A. The monthly and annual bill impacts for a typical residential customer using 653  
18 therms per year is shown on Exhibit No. \_\_ (RJA-5) The average monthly increase  
19 for this residential customer under the Company's proposed rate design is \$2.12 or  
20 4.47 percent. Monthly residential bill impacts over a range of usage are depicted on  
21 page 1 of Exhibit No. \_\_ (RJA-6).

1 **Q. Have you prepared bill comparisons for Cascade’s other non-residential tariff**  
2 **schedules?**

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

**VIII. DETERMINATION OF ALLOCATED GAS RESOURCE**  
**DEMAND COSTS**

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

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

19 **Q. Please describe what drives Cascade’s decisions regarding the use of pipeline**  
20 **capacity.**

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

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

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

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

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

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

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

7 **Step 2:** In order to have sufficient volumes in storage to serve the winter sales volumes,  
8 storage injections must be made using flowing gas and year-round pipeline capacity.  
9 Average summer injection requirements for Jackson Prairie and Plymouth LNG are  
10 8,259 Dth/day. Cascade could schedule its injection requirements around its customer  
11 requirements and operate all summer long with 8,259 Dth/day of pipeline capacity.  
12 Because this capacity is needed specifically to fill storage, which is in turn used to serve  
13 winter sales volumes, it is reasonable to allocate the costs of this capacity to Winter  
14 Sales Volumes. This capacity is also available to flow additional gas to serve winter  
15 sales volumes after the summer injection period (Step 3).

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

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

6        **Step 5:** Cascade considers its Design Peak Sales Requirement and the deliverability of  
7        all of its storage and peaking resources that have not already been considered in use on  
8        the average winter day. Cascade's estimated design peak requirement for the 12 months  
9        ended December 2016 was approximately 262,836 Dth/day. Cascade's peaking and  
10       storage resources provide, at maximum deliverability, a total of 78,299 Dth/day (9,577  
11       from Jackson Prairie and 68,722 from Plymouth LNG). However, Cascade has already  
12       relied on 1,371 Dth/day from Jackson Prairie on an average winter day in Step 3, thus  
13       incremental storage and peaking provide a resource of 76,928 Dth/day (78,299 minus  
14       1,371). It is reasonable that the costs of the various resources that provide this  
15       incremental deliverability should be allocated based on their use to serve the design peak  
16       requirements of the system.

17       **Step 6:** The design peak demand is not yet met, and no additional gas storage or  
18       peaking resources are available in a cost effective manner. Cascade thus must use  
19       additional year-round pipeline capacity of 180,827 Dth/day (262,836 minus 29,975  
20       minus 8,259 minus 58,886 minus 78,299 plus an approximate reserve of 93,410) to  
21       make up the shortfall. Because this last increment of pipeline capacity is required only  
22       to serve the design peak day requirements of the customer demand, it is reasonable to  
23       allocate the cost of this capacity based on the contribution of various customer classes to

1 design peak day demand. Exhibit No. \_\_ (RJA-7), pages 2 and 3, illustrates the six steps  
2 described above in both tabular and graphical format, respectively.

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

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

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

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

17 **Q. Does this conclude your direct testimony?**

18 A. Yes.