Exhibit No. __ (RJA-9T)
Docket No. UG-170929
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-170929

CASCADE NATURAL GAS CORPORATION

REBUTTAL TESTIMONY OF RONALD J. AMEN

March 23, 2018

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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. Did you provide direct testimony in this proceeding?

A. Yes. I previously sponsored the following direct testimony and exhibits:

- Exhibit No. __ (RJA-1T) Direct Testimony of Ronald J. Amen
- 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

Q. Please briefly summarize the subject of your direct testimony and the topics you will cover in your rebuttal testimony.

A. In my direct testimony I presented Cascade's Cost of Service Study ("COSS") and discussed its results, and I presented the various rate design proposals filed by

Cascade in this proceeding.

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

- Cascade's COSS – Cost Causation Principles for Cost Allocation
- Cascade's Support for Proposed Class Revenues
- Cascade's Rate Design Proposals
- Appropriate Cost Basis for Gas Resource Demand Costs by Customer Class for Use in Cascade's PGA Filings

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

A. The following exhibits accompany my testimony.

- Exhibit No. __ (RJA-10) Revised Summary of COSS Results at Proposed Revenue
- Exhibit No. __ (RJA-11) Revenue Requirement by Customer Cost Component
- Exhibit No. __ (RJA-12) American Gas Association Energy Analysis, "Natural Gas Utility Rate Structure: The Customer Charge Component – 2015 Update"
- Exhibit No. __ (RJA-13) Revised Rate Design at Proposed Revenue

II. CASCADE'S COSS – COST CAUSATION PRINCIPLES FOR COST ALLOCATION

A. Cascade's Presentation in Direct Testimony

Q. Please summarize why utilities conduct cost allocation studies as part of the regulatory process?

A. As I described in my direct testimony, 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, the 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.

For a gas utility, detailed studies are not required to assess the impact of additional consumption by existing customers since the distribution 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 fundamentally represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service, hence the term "Cost Causation." The requirement to develop cost studies results from the nature of utility costs.

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 from day-to-day or season-to-season. 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 practical perspective. The development of cost studies requires an understanding of the operating characteristics of the utility system.

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

A. The allocation of costs using cost of service studies is <u>not</u> 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.

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

A. The key to a reasonable cost allocation is an understanding of the primary underlying principle 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 gas 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 <u>peak design day capacity requirements</u> 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.

At issue in the proceeding, 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 related contracts for pipeline and storage services upstream of the city-gate also have a capacity-related component of cost relative to the Company's requirements for serving daily peak demands and the winter peaking season.

By contrast, 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. These cost causation factors are further discussed later in my rebuttal testimony as they apply to the position of Commission staff witness Melissa Cheesman's testimony related to the allocation of gas supply related capacity costs recovered in Cascade's Purchase Gas Adjustment ("PGA") mechanism.

B. Positions of the Parties

Q. Please summarize the parties' proposals related to Cascade's COSS.

A. Commission Staff witness Melissa Cheesman recommends the Commission reject Cascade's COSS, address the merits of various COSS methodologies in the ongoing generic proceeding[1] and make no determination regarding Cascade's use of design day in allocating natural gas peaking costs. Ms. Cheesman also recommends that Cascade's load forecasting model should be rejected as an alternative to an actual load research study that tracks actual daily therm usage for its core customers. [2]

NWIGU witness Bradley Mullins believes the COSS is flawed and should be rejected. Mr. Mullins takes issue with the COSS because Cascade did not provide a load study to help determine the core classes' responsibilities for daily therms at city gates and he disagrees with the use of the Company's use of the Peak and Average ("P&A") methodology, especially in light of the collaborative effort underway in the generic proceeding.[3]

[1] *Wash. Utils. & Transp. Comm'n v. Avista Corp., dba Avista Utils.*, Docket Nos. UE-160228, *et al.*, Order 06, ¶116 (Dec. 15, 2016).
[2] Cheesman, Exh. MCC-1T at 4:13-14 and 5:4-8.
[3] Mullins, Exh. BGM-1T at 26:16-23.

C. Cascade's Rebuttal Position

1. The P&A Allocation Method is Appropriate for Application in Cascade's COSS and Should be Accepted

Q. Please summarize your understanding of prior COSS related policy determinations by the WUTC?

A. As stated in my direct testimony, 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, P&A, 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.

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 P&A methodology in greater detail as it has been applied in the Cascade COSS.

A. As discussed in my direct testimony, The P&A methodology allocates demand-related costs to the classes of service on the basis of system and class load factor characteristics. The P&A methodology adopted in the referenced WUTC docket 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 fact 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 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. Included in Staff witness Ms. Cheesman's key "cost causation" principles is one that stresses cost allocations should be driven first by how the system is used and second by the reason the system was built.[4] Do you agree?

A. No. The P&A demand allocation method is structured to balance the manner in which capacity costs are incurred with the way the distribution system is used. In my opinion, Ms. Cheesman's first cost causation principle conflicts with her second principle, which is, to paraphrase: cost causers should pay.[5] Very few costs are driven by day-to-day throughput on the distribution system; for example, variable costs such as the level of lost and unaccounted-for gas and odorant levels, and certain fixed maintenance costs related to wear and tear on various components of district regulator station equipment.

Ms. Cheesman misinterprets cost causation. The U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit) recently quoted and elaborated on the definition of cost causation, stating:

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[4] Cheesman, Exh. MCC-1T at 7:4-6.

[5] Ibid, 7-9.

> "All approved rates must reflect to some degree the costs actually caused by the customer who must pay them. Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party. To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed."[6]

Note that there is no preference stated here for day-to-day usage of the utility system over the capital cost of building it.

Q. Do you accept the recommendations of the Staff and NWIGU that the Commission should reject Cascade's COSS in view of the ongoing generic cost of service proceeding?

A. No. First, there has been little progress in the generic gas cost of service proceeding. I attended the Staff's initial meeting of stakeholders in the generic proceeding on February 8, 2017. The timeline that was presented in that meeting called for the collaborative process to take place during the months of April through December 2017, with an issues list to be published in December 2017. While there have been a few on-line polls and emails related to future meetings, none have been scheduled to date for the bifurcated gas group. Therefore, I see no reason to hold hostage the use of Cascade's

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[6] Illinois Commerce Comm'n v. FERC, 576 F.3d 470, 476 (7th Cir. 2009) (Illinois Commerce Commission) (citing K N Energy, 968 F.2d at 1300; Transmission Access Policy Study Group v. FERC, 225 F.3d 667, 708 (D.C. Cir. 2000); Pacific Gas & Elec. Co. v. FERC, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004); Midwest ISO Transmission Owners v. FERC, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (Midwest ISO Transmission Owners); Alcoa Inc. v. FERC, 564 F.3d 1342 (D.C. Cir. 2009); Sithe/Independence Power Partners, L.P. v. FERC, 285 F.3d 1, 4-5 (D.C. Cir. 2002) (Sithe); 16 U.S.C. 824d).

COSS for the purpose of providing guidance in class revenue apportionment and rate design to the outcome of the generic proceeding.

Second, in a recent Final Order in a Puget Sound Energy ("PSE") general rate proceeding, the Commission accepted PSE's use of the P&A methodology for allocating the costs of gas distribution mains. The Commission further stated that while not expressing its preferences concerning the cost of service methodologies used in that proceeding, it would maintain the status quo and allow the all parties the opportunity to continue participating in the generic cost of service proceedings.[7]

2. Design Day Peak is Superior to an Actual Peak Day for the Allocation of Gas Transmission and Distribution Mains Costs

Q. Why did you choose to utilize Cascade's design day demand 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 engineering and construction costs are incurred, to meet design day demand. In contrast, costs are not incurred based on 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.

[7] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket Nos. UE-170033 and UG-170034 (Consolidated), *et al.*, Order 08, ¶17 and 19 (Dec. 5, 2017).

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 gas supply related pipeline and storage capacity 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 COSS.

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 gas supply portfolio would tend to vary and make the installation of facilities and acquisition of supply capacity resources 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.

Q. Is the use of actual periodic peak demands appropriate in view of the Commission's historic preference for balancing the allocation of distribution system costs between cost causation and the actual day-to-day use of the system?

A. No. The use of actual peak day demands, rather than design day demands, would result in the allocation of virtually all of Cascade's distribution system costs based on the day-to-day use of the system versus the basis on which the design, engineering and construction costs were incurred; namely, the system design day planning criteria. Over the last six years, Cascade's actual Washington system peak day demands of its heat sensitive, core customer classes have ranged from 43% (2015) to 22% (2017) below design day demand levels. Cascade cannot reliably make long-term investments in its gas distribution facilities and upstream firm pipeline and storage contracts based on these varying actual peak demand levels. Further, approximately half of Cascade's transmission and distribution mains costs are allocated based on test year throughput under the Average portion of the P&A methodology, a measure of actual use of the system.

Q. Does the particular approach employed in the application of the P&A method in the Cascade COSS serve to mitigate the impact of the use of a Design Day peak on the core customer classes?

A. Yes. Included in the Peak portion of the P&A allocator for application in the Cascade COSS are the measured average daily demands of Cascade's non-core, large transportation and special contract customers during the three-day system peak from the test year. This results in 52% of the costs of transmission mains and the subset of distribution mains that serve these non-core classes to be allocated to them under the Peak component of the P&A allocation factor, a further usage based contribution by the non-core classes in the allocation of these costs.

Q. Is the use of Design Day Peak for the allocation of capacity related gas transmission and distribution costs prevalent in the gas utility industry?

A. Yes. While I haven't commissioned a survey of all 50 state jurisdictions, over the course of my career in the gas and electric utility industry, 36 out of 40 natural gas utilities, in rate cases or generic investigations with which I am either familiar or have provided expert testimony – involving 30 state jurisdictions – a Design Day Peak allocation method was authorized or uncontested for gas transmission and distribution capacity costs.

Q. Is there recent Commission guidance related to the use of Design Day Demands in the application of the P&A allocation method?

A. Yes. In the previously referenced PSE Order, the Commission accepted the use of design day peak for application in the P&A method and rejected the Staff proposal to allocate peak demand costs based on the average class use from the highest five-day period in each of the previous three years because it placed too much emphasis on the use of the system, as opposed to how the system is designed.[8]

3. A Load Research Study of the Type Proposed by Staff is an Unnecessary and Expensive Exercise for Cascade's COSS and Rate Design Purposes

Q. Please briefly describe the nature of a load research study.

A. Load research studies typically involve installing special metering devices on a sample of customers so that consumption data can be collected at daily, hourly or even minute-by-minute intervals. The data from such studies can be used for a number of purposes.

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[8] Ibid, ¶17.

Traditionally, load research has supported load forecasting activities, complex rate design studies, integrated resource planning, demand-side management planning and impact evaluation, and system operations planning.

Load research projects are complex undertakings that involve coordination among several areas of an energy utility. Some significant steps include:

- Study design and planning
- Sample selection
- Customer selection and recruitment
- Installation of measurement and communication devices
- Data retrieval, storage and editing
- Data analysis and applications

Each stage of the process must be carefully conducted to ensure the integrity of the load study. Decision points occur at the design and sample selection stages regarding time intervals between meter readings, time period for data collection, and degree of customer segmentation; choices that are determined by the purpose of the load study. Customer recruitment and equipment installation must be completed in a manner that maintains the integrity of the load sample and data retrieval must be monitored to minimize loss of load data and to correct measurement errors. In the end, statistical and other analysis must be performed to draw meaningful conclusions from the consumption data.[9]

Q. Are load research studies of the type you just described more commonplace in the electric utility industry than for natural gas utilities?

[9] *Load Forecasting Methods,* American Gas Association Statistics and Load Forecasting Methods Committee. Copyright, 1995.

A. Yes. The electric utility industry conducts extensive load research programs; numerous useful studies and technical manuals are available from industry organizations such as the Edison Electric Institute and the Electric Power Research Institute. My colleagues at Black & Veatch and I recently completed load research studies for two electric utility clients in 2017; the first of which, a Net Energy Metering ("NEM") load research study conducted for CPS Energy ("CPSE"), San Antonio, TX, consisted of an analysis of CPSE's solar production data and NEM billing data. The load research study provided the following hourly data streams:

- Counterfactual load (i.e., the total load of a customer assuming no solar facility);
- Load delivered to customer by CPSE;
- Excess load generated by customer into the CPSE system, and
- Solar generation utilized on-site by customer (i.e., the "Add-back" amounts

The foregoing results were incorporated into CPSE's weather normalization process.

The second load research study was performed for Westar Energy ("Westar"), headquartered in Topeka, KS. For the entirety of Westar's test year, 15-minute interval energy consumption data was available for a sample of solar Distributed Generation ("DG") customers. Automated Meter Infrastructure ("AMI") recorded kWh delivered to solar customers and exported from solar customers on separate channels. Sample interval data and monthly billed kWh deliveries and exports for DG customers was used to obtain a load profile for a new DG customer class in Westar's COSS.[10] The two examples of electric load research studies provide a contrast to the purpose for which the

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[10] *Kansas Corporation Commission v.Westar Energy, Inc.*, Docket No. 18-WSEE-328-RTS. Amen Testimony at 24:14-17 and 25:1-2, February 1, 2018.

Cascade load research study is intended, the determination of a coincident peak day demand for each of its core customer classes for use in the COSS. The two complex electric load research studies were initiated to determine the respective hours in a day when solar DG customers were exporting excess self-generated electric load to the distribution system or receiving electric load from the utility; the purpose for which was two-fold: 1) assigning costs to the DG class of customers for their use of the distribution system and the native generation resources they use, and 2) to value the excess solar generated load placed on the distribution system, based on avoided generation and transmission costs, in order to properly reimburse the DG customers. By comparison, the proposed load research study for Cascade is a solution looking for a problem that doesn't exist.

Q. Will the eventual deployment of AMI equipment throughout Cascade's service territory on the premises of its core customer classes facilitate load research projects?

A. Yes. However, for purposes of daily collection of consumption data from the respective core customer groups and recognition of geographical differences where average heating degree day ("HDD") levels may vary, a sample size for each and the duration of the sampling period must be determined. An acceptable level of sampling error must be established as well as an estimate of the mean and variance of the population from which the sample will be drawn. Even with the installed AMI equipment, Cascade will still be required to pay a third-party provider for the compilation, storage and transfer of the daily sampled consumption data over the course of several months of a heating season. Following computation of the mean base load and temperature sensitive factors for each sampled subpopulation, it will then be necessary to adjust the sampled consumption data from a single heating season to the core classes' respective populations as well as the use of regression analysis to align the class level recorded demands captured under periodic peak day weather conditions with Cascade's design day weather planning criteria.

Q. In your opinion, does the load research study advocated by Staff represent an improved and cost-effective approach to determining class level design day peak demands for use in Cascade's COSS and PGA filings?

A. No. First, notwithstanding the potential program pitfalls and data weaknesses that I alluded to earlier, which load research studies might encounter, adequate consumption data already exists in years of monthly billing records for the entire population of Cascade's core customer classes; from which statistically sound regression analysis results are currently produced on an ongoing basis that provide reliable class level design day peak demands for use in both the COSS and in the assignment of core class responsibility for the capacity resource allocations for use in Cascade's annual PGA filings.

Second, in order to ensure satisfaction of core customer demand on the coldest days, Cascade's load forecast methodology, as detailed in its IRP,[11] develops three peak day usage forecasts. These peak day forecasts enable Cascade to make prudent distribution system and gas supply related resource capacity planning decisions to fulfill its responsibility to provide adequate heating load under all but force majeure conditions, particularly as most space-heating customers will have no alternative heating

[11] Cascade Natural Gas Corporation, 2016 Integrated Resource Plan: UG-160453, Section 3 Demand Forecast.

source during the coldest days in the event gas does not flow. The three weather scenarios that are analyzed in the Cascade forecasting model are the following:

- Average peak HDDs;
- System-wide max peak HDDs; and
- Max city gate peak HDDs.

Each individual city gate load center's forecasted peak demand is determined by rate class.[12]

The forecasting methodology employed by Cascade in each of its IRPs is fully vetted by the Technical Advisory Group, including Commission Staff, and Cascade continually pursues enhancements to its demand forecasting methods, as documented in its Two-Year Action Plans. It logically follows that the design day demands of its core customer classes that are produced from this rigorous and fully transparent process should be employed in the allocation of peak demand related distribution costs in the COSS and in the assignment of upstream pipeline and storage capacity costs in the Company's PGA filings.

Q. In your experience, have you conducted load research studies from sampled customer populations for gas utilities for the purpose of determining class level contributions to peak day demands?

A. No. Moreover, as a former member of the A.G.A. Statistics and Load Forecasting Methods Committee, I am only aware of a single instance whereby a natural gas utility,

[12] Ibid, Appendix B.

Washington Gas Light, was ordered by a regulatory commission to conduct such a load research study for its Maryland service territory.[13]

III. CASCADE'S SUPPORT FOR PROPOSED CLASS REVENUES

A. Cascade's Presentation in Direct Testimony

Q. Please describe the approach generally followed to apportion Cascade's proposed revenue increase of $5.9 million to its customer classes in the Company's initial filing.

A. As described in my direct testimony, the apportionment of revenues among customer classes consisted 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 discussed in my direct testimony 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.

Q. What was the result of this process?

[13] *Maryland Public Service Commission v. Washington Gas Light,* Order No. 84475; Case No. 9267; November 14, 2011.

A. After 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. 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 indicated 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 potential 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. From a class cost of service standpoint, this type of class movement, and reduction in the existing class rate subsidies, is desirable.

B. Positions of the Parties

Q. Please summarize the parties' recommendations related to Cascade's proposed class-by-class revenue allocation.

A. Staff witness Ms. Cheesman recommends Cascade's proposed class revenue allocation be rejected in favor spreading Staff's proposed revenue requirement decrease to all customer classes on an equal percentage of margin basis.[14] NWIGU witness Mr. Mullins also recommends the resulting increase or decrease in this proceeding should be spread on an equal percent of margin basis to each schedule, except for Special Contracts. His recommendation is largely based on his view that without a load study to determine actual core class responsibilities of daily therms at the city gates it is inappropriate to spread rates based on the results of a COSS, "because the underlying data is flawed, outdated and unreliable,"[15] although he provides no evidentiary basis for his opinion. The Energy Project's ("TEP") witness, Shawn M. Collins, recommends that a "more fair approach would be to allocate any rate increase allowed on an equal percentage basis across all customer classes," citing one of the three primary criteria for sound rate design that I addressed in my testimony, fairness to customers.[16]

C. Cascade's Rebuttal Position

Q. Please summarize your response to the primary underlying rationale of the witnesses' unanimous recommendation to employ an equal percent of margin approach to apportioning the authorized revenue requirement to the respective customer classes.

[14] Chessman, Exh. MCC-1T at 3:15-17.
[15] Mullins, Exh. BGM-1T at 27:17-20.
[16] Collins, Exh. SMC-1T at 13:12-13 and 16-18.

A. Earlier in my rebuttal testimony, I addressed the primary rationale expressed by both witnesses Ms. Cheesman and Mr. Mullins for the use of an equal percentage of margin basis for class revenue allocation; namely, the lack of a load research study and the ongoing generic cost of service investigation. Regarding the opinion of TEP witness Mr. Collins, I can only say that his view of fairness is different than my own. However, I must correct one statement by Mr. Collins that none of the revenue increase was allocated to commercial and industrial classes.[17] The Tariff Schedules 570/577 and 663, which are targeted for revenue increases, are entirely comprised of commercial and industrial customers.

Q. Staff witness Ms. Cheesman states that even if the Commission were to accept the Company's proposed COSS model, Staff's recommendation for an equal percent of margin revenue allocation would still be the equitable outcome given that little or no cross-class subsidization is currently present. Do you agree?

A. No. An equal percentage of margin revenue allocation, whether increase or decrease, would exacerbate the current level of interclass cross-subsidization. In other words, under an equal percentage of margin revenue allocation, the result for all customer classes would be movement further away from parity. More importantly, the classes would move further away from each other, which directly contradicts the goal of matching class revenue to cost of service. In the following Table 1, I have provided: a) current revenue-to-cost and parity ratios from the updated COSS under Cascade's proposed revenue requirement of $215,514,692; b) proposed revenue-to-cost ratios and

[17] Ibid, at 13:10-11.

apportionment of the overall revenue decrease of $1,677,217; and c) the corresponding class-by-class percentages of the system average decrease.

<u>Table 1 – Updated COSS Revenue-to-Cost and Parity Ratios</u>

	Total Company	Residential (Sch. 503)	Commercial (Sch. 504)	Industrial (Sch. 505)	Large Volume (Sch. 511)	Interruptible (Sch. 570)	Transport (Sch. 663)	Special Contracts
Revenue-to-cost	1.01	0.96	1.08	1.05	1.06	1.00	0.96	1.28
Parity	1.00	0.95	1.07	1.04	1.05	1.00	0.95	1.27
Proposed Revenue-to-cost	1.00	0.95	1.07	1.04	1.05	1.00	0.95	1.28
Amount of Decrease	$1,667,217	$816,236	$573,072	$50,225	$37,992	$3,866	$195,825	$0
% of 1.8% Average Decrease	100%	100%	135%	135%	135%	100%	75%	0%

The source for the table is my rebuttal Exhibit No. ___ RJA –10, Revised Summary of COSS Results, which includes my revised class-by-class revenue allocation proposal.

IV. <u>CASCADE'S RATE DESIGN PROPOSALS</u>

A. Cascade's Presentation in Direct Testimony

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. Among these principles are the following, which were relied upon as the basis for Cascade's rate design proposals:

1. Efficiency;
2. Cost of Service;

3. Stability; and
4. Non-Discrimination;

These rate design principles are discussed in my direct testimony and 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 summarize the rate design changes Cascade has proposed in this rate proceeding.

A. The specific rate design changes and supporting rationale for Cascade's proposals are discussed in my direct testimony. The table below lists the current and proposed monthly fixed charges in Cascade's current tariff schedules, which were the focus of the response testimonies of Staff witness Ms. Cheesman and TEP witness Mr. Collins. Cascade proposes to ratably adjust the corresponding volumetric rates in each respective rate schedule based upon of the final authorized revenue requirement resulting from this rate case proceeding.

Table 2- Cascade's Current and Proposed Fixed Charges

	Basic Service Charge		Demand Charge	
Customer Class	**Current**	**Proposed**	**Current**	**Proposed**
Residential - 503	$4.00	$6.00		
Commercial - 504	$10.00	$15.00		
Industrial - 505	$48.00	$75.00		
Large Volume - 511	$100.00	$200.00		
Interruptible - 570	$130.00	$500.00		
Transport - 663	$500.00	$750.00	$0.20	$0.22

B. Positions of the Parties

Q. Please summarize the positions of the responding parties to Cascade's proposed level of Basic Charges.

A. Staff witness Ms. Cheesman recommends that basic charges remain unchanged because of Staff's recommended revenue decrease and maintaining the current level of basic charges provides rate stability to both ratepayers and the Company.[18] TEP witness Mr. Collins only recommendation is an increase of $1.00 to the Residential Basic Service Charge in Tariff Schedule 503.

C. Cascade's Rebuttal Position

Q. Do you find the proposals by Ms. Cheesman and Mr. Collins reasonable?

A. No. The only rate stability in the Staff proposal would be to one rate component, the Basic Service Charge. Whether a revenue requirement increase or decrease is authorized by the Commission in this rate case proceeding, persuasive cost support from the COSS demonstrates that a fair and equitable adjustment to Cascade's Basic Service Charges is warranted, as well as an adjustment to the Demand Charge in Tariff Schedule 663. Exhibit No. __ (RJA-11), Revenue Requirement by Customer Cost Component, provides a detailed breakout of the specific customer related costs by class from the Unit Cost Report in the COSS. For the Residential class, the primary focus of both Ms. Cheesman and Mr. Collins, the unit cost for Billing, Meter Reading, and Customer Service (e.g., call center) expenses; and the return and depreciation expense for a Residential Meter, Regulator and Service Line is $8.76 per customer, per month; which is more than double the $4.00 Residential Basic Service Charge. The exhibit shows that the proposed Basic Service Charges for the remaining commercial and industrial customer classes remain well below their respective indicated total customer related revenue requirement, as described in my Direct Testimony.

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[18] Cheesman, Exh. MCC-1T at 14:5-7.

Q. How does Cascade's residential Basic Service Charge compare to the monthly customer charges for residential customers of other utilities?

A. Exhibit No. ___(RJA-12) American Gas Association Energy Analysis, "Natural Gas Utility Rate Structure: The Customer Charge Component – 2015 Update" contains a comparison of the monthly customer charges for residential service from 197 natural gas distribution utilities from rate jurisdictions in all states and the District of Columbia. The purpose of the A.G.A. analysis was to illustrate then current levels of customer charges, estimate the portion of fixed costs that these charges cover, and track their historical growth. The median residential customer charge in 2015 was $11.25 per month. By comparison, Cascade's current residential Basic Service Charge of $4.00 per month is less than half of the 1st quartile level of $9.00. Interestingly, the gas distribution utilities in the Pacific –West U.S. Census Region (Washington, Oregon, and California) in 2015 had the lowest level of median monthly customer charges at $4.95. In Washington, however, both Avista Utilities and PSE currently have gas residential basic charges well above Cascade's Basic Service Charge.

Q. Have you reflected the class revenue decreases in the rate components of the various rate schedules?

A. Yes. Exhibit No. __ (RJA-13), Revised Rate Design at Proposed Revenue, presents the adjustments to the volumetric Delivery Charges in each of the rate schedules to apply the corresponding proposed revenue decreases by class.

V. APPROPRIATE COST BASIS FOR GAS RESOURCE DEMAND COSTS BY CUSTOMER CLASS FOR USE IN CASCADE'S PGA FILINGS

A. Cascade's Presentation in Direct Testimony

Q. What was the purpose of your Direct Testimony on the topic of Cascade's gas resource demand costs?

A. The subject of my Direct Testimony described the manner in which Cascade plans for and utilizes the gas transportation and storage capacity that is needed to serve its natural gas sales customers. I provided a recommendation as to the allocation of pipeline capacity and storage costs for use in Cascade's PGA filings.

Q. Please summarize 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, storage and peaking capacity?

A. The process for determining the need for pipeline, storage and peaking capacity was summarized in the six-step process described in my Direct Testimony,[19] as supported by the analysis provided in my Exhibit No. __ (RJA-7). 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. What are the resulting unit demand cost rates for the various sales service classes in the PGA that resulted from your recommended allocation of year-round pipeline capacity, storage, peaking and redelivery capacity (TF-2) costs?

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) to my direct testimony.

B. Positions of the Parties

Q. Please summarize the positions of the responding parties on this topic.

A. Staff Witness Ms. Cheesman was the only respondent to challenge the Company's proposed allocation of gas supply related pipeline capacity, storage, and peaking costs. The basis of Ms. Cheesman's recommendation to reject the proposed allocation of these gas supply related capacity costs was her opposition to the use of a Design Peak Day and her related support for the completion of a load study before the PGA cost allocations could be changed.

C. Cascade's Rebuttal Position

Q. What is your response to Ms. Cheesman's recommendation?

[19] Amen, Exh. RJA-1T at 41:21 to 44:2.

A. Earlier in my Rebuttal Testimony, I dealt with Ms. Cheesman's objection to Cascade's use of a Design Day Peak and her support for a load study as a prerequisite for allocation of peak demand related costs in its COSS. My reasoning and evidentiary support apply equally to this topic as well. I would add that the methodology employed in my analysis and the use of a Design Day Peak as part of that analysis is comparable to that employed by PSE for the allocation of its pipeline, storage and peaking capacity costs in its PGA for at least the last decade. The Commission should approve the proposed unit demand and commodity cost rates contained in Exhibit No. __ (RJA-7) for application to the various sales service classes in Cascade's 2018 PGA filing.

VI. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. My findings and recommendations are summarized as follows:

- The P&A allocation method is appropriate for application in Cascade's COSS and should be accepted by the Commission for the purpose of providing guidance for class revenue allocation and rate design;
- Design Day Peak is superior to an actual peak day for the allocation of gas transmission and distribution mains costs as well as Cascade's supply related pipeline, storage, and peaking costs, and should be accepted by the Commission;
- A Load Research Study of the type proposed by Staff is an unnecessary and expensive exercise for deriving the core customer class' peak day demands for use in Cascade's COSS, revenue allocation and rate design purposes;
- The Commission should approve the Company's proposed revenue decrease apportionment to the respective rate schedules and the resulting proposed rates; and

- The Commission should approve the proposed unit demand and commodity cost rates contained in Exhibit No. __ (RJA-7) for application to the various sales service classes in Cascade's 2018 PGA filing.

Q. Does this conclude your direct testimony?

A. Yes.