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Filed Via Web Portal

Mr. Mark L. Johnson, Executive Director and Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
Olympia, WA 98504-7250

RE: Comments of Avista, Cascade Natural Gas, NW Natural Gas, Pacific Power & Light Company, and Puget Sound Energy on Rulemaking to Address Electric and Natural Gas Cost of Service, Dockets UE-170002 and UG-170003

Dear Mr. Johnson:

These comments are submitted on behalf of Avista, Cascade Natural Gas, NW Natural Gas, Pacific Power and Puget Sound Energy (collectively, the "Parties", minus Pacific Power the "Gas Parties," and absent Cascade Natural Gas and NW Natural Gas, the "Electric Parties") in response to the Notice of Opportunity to File Written Comments, issued by the Washington Utilities and Transportation Commission (the "Commission") in the above referenced dockets on July 23, 2018 (the "Notice"). The Parties appreciate the opportunity to provide input on the extent to which rules should define cost of service study ("COSS") attributes and the methods and practices implemented to calculate and present COSS in general rate proceedings.

The Parties believe that there should be a clear policy rationale for any new rules or requirements and company characteristics, customer characteristics, and history should be considered when adopting any standardized rules. Many varied cost of service ("COS") issues cannot effectively be addressed through one rulemaking. The Parties address each question posed by the Commission in the format of the Notice below.

Sincerely,

/s/ Jon Piliaris

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<u>Questions affecting both electric and natural gas companies:</u>

1. **To what degree should rules define the presentation (such as per class revenue and costs, parity ratios, revenue changes, billing determinants, etc.) of cost of service studies?**

The Parties support a common format for the output schedules of a COSS as part of the specified set of Minimum Filing Requirements (MFRs) for general rate cases, which are not uncommon among utility commissions. Examples may include: Summary schedules showing COSS results by customer class at present and proposed system rates-of-return; functionalized and classified revenue requirement results by customer class; and functionalized and classified unit costs by customer class. However, the rule should not be prescriptive as to the structure, computational processes, and functionality of the COSS model itself, provided the structure of the COSS model is transparent and auditable.

a. **Are standardized presentation formats or templates an adequate way to enable comparisons of cost of service studies?**

Yes.

b. **To what degree should templates be relied upon for summary presentations versus underlying modeling and work papers?**

See initial paragraph under Question 1.

c. **How should a party sponsoring a cost of service study present the interface between a revenue requirement study and a cost of service study?**

The Parties support the presentation of a reconciliation of the proposed total Test Year revenue requirement with the class-by-class results of the COSS. The interface can be accomplished through: 1) the COSS summary schedules that present the Income Statement conforming to the total revenue requirement, and 2) the COSS input schedules from the revenue requirement, where the FERC account level detail for Rate Base, O&M and A&G are presented.

d. **Should parties present a list of all allocation factors, including how they are calculated, how the calculation method has changed from its inception, and where they are used?**

The Parties believe it could be cumbersome and wasteful to require a description of each calculation since its inception. The proposed rules under WAC 480-07-510(6) require sufficient historical background and the Commission may request additional detail on a case by case basis to assist in its decision making. WAC 480-07-510(6) as proposed requires that the company's initial filing "…(b) identify all cost studies conducted in the last five years for any of the company's services and (c) describe the methodology the company used in all such cost studies." The Parties believe this historical look is sufficient and, may be more than necessary in certain cases. Finally, a list of where each allocation factor is used seems duplicative, as it is included and can be determined in the COSS itself.

2. Should the Commission adopt rules requiring parties to conduct and present a load study when performing cost of service studies? Please explain why or why not.

The Parties that already supply load studies as part of their COSS would support continuing to do so. However, while the Parties appreciate general guidelines to meet the Commission's expectations from a load study, setting detailed and rigid rules regarding the study methodologies would be harmful and cause an unnecessary burden to utilities. There are many statistical methodologies and valid tools available to perform load studies. Utilities should be allowed to choose the most appropriate methodology to fit their particular customer mix and size conditions, data availability, and resource limitations.

a. If the Commission were to require a load study in rule, what is an appropriate definition of a load study? Which parameters are necessary to include in a load study?

It is difficult to determine one definition or set of parameters that would be appropriate for all load studies. One possible appropriate definition of a load study could be, a "statistical analyses of interval load data collected from sampled customers to estimate hourly (electric) or daily (natural gas) load profiles of given classes."

b. If a rule requires load studies, what level of specificity, in terms of measuring customer's loads, should the Commission require to be presented in load studies?

See the response to answer to 2(a) above.

c. How frequently should companies perform load studies?

See initial paragraph under Question 2.

d. How might emerging technologies, such as Advanced Metering Infrastructure (AMI), affect the timing and frequency of load studies? Please also explain whether and how selective deployment of AMI could minimize load study costs to ratepayers.

Although the quality of the interval load readings collected from the sampled customers is expected to improve with AMI and the corollary time and effort required for VEE (verify, estimate and edit) would therefore be reduced, it is not certain how significant the resource savings would be. Several of the Parties are just in the beginning of rolling out this new technology and sufficient data is not yet available on the increased accuracy and reliability of the meter readings. It will take time to reach the level of infrastructure necessary to judge any changes needed/permitted in the load study timing or frequency by this technology shift.

Selective deployment of AMI could reduce AMI's benefits and increase costs to customers. AMI technology generally requires a robust network of meters to meet its full potential. Therefore, it is critical that the planning of the roll out of this system be managed by each utility for its unique system in such a way that maximizes AMI's technology and reliability benefits. Dictating a roll out of AMI to a select group of customers could delay installation, add to the cost of implementation, and likely would not produce the results desired.

3. Should the Commission allow parties to include confidential information in a cost of service study?

Yes. The COSS should be treated in a consistent manner as any other documents filed with the Commission.

a. If so, should confidential information be labeled in the same way as all other information identified as confidential under WAC 480-07-160?

Consistent with the new draft rules for spreadsheets in WAC 480-07-160, the COSS should identify the confidential information within the document in a way that is not impractical or unduly burdensome. In the case of large voluminous workbooks, requiring utilities to designate confidential information on a cell-by-cell basis would be extremely difficult.

b. What circumstances would require a party to provide a confidential version of a cost of service study?

The Parties are not currently using confidential information in COSS. If the Commission requires the use of a different COS methodology or circumstances change, however, the need for confidentiality may arise.

4. **Should the Commission adopt rules that require parties to include in cost of service studies the reconciliation between test year billing determinants and billing determinants used in the cost of service model?**

Billing determinants are not representative of COS allocation factors and a reconciliation between test year and COS model billing determinants would not be necessary. To the extent that test year billing determinants are components of some COS allocation factors, the reconciliation is already provided in workpapers showing the source/development of the allocation factors.

a. Similarly, should the Commission require cost of service studies to include a reconciliation for unadjusted and pro forma revenues and the resulting cost of service models?

The Parties need more information as to what the unadjusted and pro forma revenues would be used.

5. Should the Commission include in a rule on cost of service studies definitions of specific terms used in cost of service studies? Please include specific technical terms that should be defined.

No; it's an unnecessary complication to a rule. There are adequate definitions of COS terminology in industry authoritative publications such as the National Association of Regulatory Utility Commissioners ("NARUC") COS and rate design manuals.

6. There are several overall methods upon which cost of service studies rely, e.g., marginal, total service, long run, incremental or embedded cost studies. Should the Commission rely principally upon a single method?

Yes. Generally, state utility commissions across the U.S. rely principally on a single overall methodology for COSSs, typically either embedded cost or some form of marginal cost.

a. **If so, what parameters should the method include? Is it necessary for the Commission or parties sponsoring a study to conduct periodic revisions of the method? What would prompt such a revision?**

The parameters should reflect the selected methodology. It may be possible that a periodic revision of a methodology may be warranted, depending on the specific circumstances of the utility and the costing and pricing requirements of an ever-evolving utility industry.

7. **How should special contract customers be treated with regard to pass-through costs (*i.e.*, separate riders identifying and recovering specific types of costs)?**

The treatment of pass-through costs relative to special contract customers should be a function of the contract terms negotiated between the utility and the customer, as approved by the Commission, and therefore subject to any contract provisions regarding specific pass-through costs ordered by the Commission.

8. **The Commission is considering rules that require a baseline cost of service study for each Company. One option for such a process would require a company to submit an initial baseline cost of service study for the Commission to review and approve. This would happen in the next general rate case each company files after the Commission adopts rules requiring such a baseline. The Commission would consider this baseline the standard approach for that company to allocate costs, inclusive of future updates with Commission approval. Thereafter, a company would be required to present adjustments to the cost of service method in comparison to the latest Commission-approved baseline.**

a. **Is this a sound approach for providing consistency for the review of cost of service studies and their underlying methods?**

Many COS elements are settled as part of a general rate case, and it would not be advantageous to have a rulemaking that imposes a baseline approach, which erects barriers to such settlements. If the historical description required under the proposed WAC 480-07-510 regarding previous COS methodologies and the detailed exhibits of the general rate case fail to provide the comparison desired by the Commission, the Parties request a workshop to more directly address the data needed and the efficiencies gained by providing this additional information.

b. **What specific topics or aspects of a cost of service study should or should not be included as a part of a baseline study?**

Please see answer to 8(a).

c. **Should there be a defined timeframe for the effective period of a baseline cost of service study before formal re-evaluation of the baseline would be required?**

No. A general rate case will provide ample opportunity for review of the baseline COSS, as circumstances dictate.

i. **Should the timeframe for re-evaluation be the same for all companies?**

See the initial paragraph under Question 8(c).

ii. Should baseline studies be established or reviewed outside of a general rate proceeding?

There should be flexibility for a utility to file a request for a revenue neutral review of a baseline COSS.

iii. Should the Commission consider re-evaluation simultaneously for all companies?

The Commission has the authority to order a generic re-evaluation of COSSs, as circumstances dictate.

d. Which metrics should be considered as the trigger for a formal re-evaluation of a baseline cost of service study?

While specific metrics are difficult to anticipate and perhaps too limiting in their application, evolving changes in the energy utility industry may uncover shortcomings in the structure and/or costing methodologies of the status quo baseline COSSs.

9. What other topics should the Commission consider in adopting rules governing cost of service studies?

The foregoing list of questions provides a thorough review of the relevant topical areas.

<u>Questions affecting electric utility service only:</u>

1. Should the Commission require marginal cost studies for special contract customers that rely upon a utility for electric generation, transmission, distribution, or a sub-set of these components?

The Electric Parties believe the nature of special contract customers can vary significantly and that in some cases a marginal cost study for a special contract customer would make no sense. At a minimum, the type of special contract customer for which a marginal cost study is appropriate should be identified.

The Electric Parties are opposed to providing a marginal cost study for special contract customers if the purpose of this study will be used to potentially adjust special contract rates during the term of the contract. The Electric Parties are not opposed to providing a marginal cost study if the purpose of the study is simply for data points—to allow parties to see how the contract is progressing over the contract's term. Even so, it is important to recognize that the special contract rule, WAC 480-80-143, addresses the standards for the Commission to consider at the time the application is submitted to the Commission for approval. Moreover, in evaluating a special contract and how it has performed, it is necessary to look at the performance over the totality of the contract, not just for one snapshot in time during a general rate case.

2. How should cost of service studies allocate demand and energy costs?

Each utility uses an allocation method that works for their specific company and circumstances. Some utilities may be open to discussing revisions to their methodology. Please see below responses to this request.

PSE currently uses a peak credit classification of demand and energy costs and finds this to be a satisfactory methodology to accomplish this allocation. The demand component of the peak credit classification is the class-level average of the coincident peak in each of the winter months of November through February ("4-CP"). The energy component of the peak credit classification is comprised of class-level loss adjusted normal delivered kWh. PSE would be amendable to exploring other alternatives to the extent that they make sense for PSE's system and customer dynamics.

Avista currently uses a peak credit classification of demand and energy costs utilizing the test year system load factor to determine the peak credit ratio applied to production and transmission costs. The demand component of the peak credit classification is allocated by the class-level average of the twelve monthly coincident peaks throughout the year (12CP). The energy component of the peak credit classification is allocated by the class-level loss adjusted test year normalized annual kWh consumption. Avista considers this methodology a reasonable approach to the assignment of these costs but would be amenable to explore other alternatives. Distribution system demand costs that are not directly assigned, are allocated by the average of the twelve monthly class-level non-coincident peaks (12NCP, using maximum diversified demand for each class).

Pacific Power does not take a specific position on any COS methodology for the purposes of this survey and does not think that any specific COS methodology should be given preference in rules. The choice of different methodologies for class cost allocations can be driven by numerous dynamic factors that change over time including, but not limited to, utility-specific operating considerations, industry trends, and customer composition. In its last general rate case (UE-140762), Pacific Power used a peak credit classification of demand and energy costs utilizing the test year system load factor to determine the peak credit ratio applied to production and transmission costs. The demand component of the peak credit classification is allocated by class loads during the top 100 hours in Winter and top 100 hours in Summer of Pacific Power's west control area loads. The energy component of the peak credit classification is allocated by the class loss adjusted test year normalized annual kWh consumption. Pacific Power considers this methodology a reasonable approach but is open to exploring other alternatives.

a. Is a single method or a set of methods the most balanced and fair to all parties involved?

The Electric Parties recognize the unique system needs and customers of each utility and have no objection to having unique energy/demand allocation methodologies utilized by the various parties.

b. **Should the Commission establish a preference for a particular method? Please explain your response.**

The methodology utilized should be flexible to reflect the conditions and customers served by the responsible utility.

c. **Are there specific methods that should not be considered by the Commission? For what reason should the Commission not consider specific methods?**

The Electric Parties decline to prescribe one uniform method for all utilities.

3. **How should cost of service studies classify and allocate:**

Each utility uses an allocation method that works for their specific company and circumstances. Some utilities may be open to discussing revisions to their methodology. Please see below responses to this request.

a. **Transmission and distribution assets?**

PSE currently allocates transmission costs based on peak credit with a 4-CP demand factor and finds this to be a satisfactory methodology, but would be open to discussing reasoned alternative methodologies. PSE currently performs a direct assignment of its distribution plant mostly based on substation loads, circuit line miles and loads, loads on transformers, forward looking meter cost studies, etc. and would prefer to continue this methodology as opposed to a general Non-Coincident Peak or Customer Allocation method.

Avista currently classifies and allocates transmission assets and expenses the same as production costs (peak credit classification, demand 12CP, generation level energy consumption) as discussed in question 2. For large industrial customers, Avista performs a direct assignment of its distribution plant, based on substation loads and circuit or conductor line miles. The remainder of demand-related distribution plant (segregated by the voltage level at which customers receive service) is allocated to the other customer groups (not directly assigned) by 12NCP as described in question 2. Customer-related distribution plant, consisting of meters and services, is allocated by number of customer-based allocators (meter allocation incorporates forward looking meter cost studies into a weighted customer allocator). Street and area lighting fixtures are directly assigned. Avista considers this methodology a reasonable approach to the assignment of these costs but would be amenable to explore other alternatives.

In its last general rate case (UE-140762), Pacific Power classified and allocated transmission costs consistently with generation costs, distribution substations and primary lines were allocated on maximum annual schedule peak, distribution line transformers and secondary lines were allocated on maximum non-coincident peak weighted by a diversity factor for classes who use those facilities, and meters and services were allocated based upon the cost of new equipment applied to customer counts. Pacific Power is open to exploring other alternatives.

b. **Fuel costs and purchased power**?

PSE currently classifies and allocates fuel costs like all generation plant – via the peak credit methodology that weights both energy and demand components in the class allocation. PSE finds this to be a sufficient method, but would be open to discussing reasoned alternative methodologies.

Avista currently classifies and allocates fuel and purchased power, as well as sales for resale and wheeling revenues, the same as all production and transmission costs, using the peak credit methodology discussed in question 2. Avista considers this methodology a reasonable approach to the assignment of these costs but would be amenable to explore other alternatives.

In its last general rate case (UE-140762), Pacific Power classified and allocated fuel costs and purchased power consistently with all other generation costs. Pacific Power is open to exploring other alternatives.

c. Common and joint costs?

For definitional purposes, common costs occur when the fixed costs of providing service to one or more classes or the cost of providing multiple products or services to the same class use the same facilities and the use by one class precludes the use by another class. Joint costs occur when two or more products or services are produced simultaneously by the same facilities in fixed proportions.

It is the existence of common costs (the primary characteristic of utility costs) that requires the cost allocation study. The need to allocate costs for ratemaking requires that cost studies be based on sound principles and that they reflect the planning and operating realities of the utility. Since no two utilities are exactly alike, there is no one best allocation methodology that may be applied as a one size fits all method. Further, systems are not static and the optimal allocation methodology may change over time as the system configuration, loads, and markets change. Rather, there is a best cost allocation method for each application that reflects how the utility is planned and operated currently. That method must be chosen based on the underlying facts. Cost causation is one such basis for assessing the best cost study for allocating common costs.

Each group or class of customers shares in the benefits of the presence of joint costs and economies of scale in proportion to their contribution to scale economies based on their own relative costs on a stand-alone basis. For example, for residential and commercial customers served from the same distribution system, the sum of the stand-alone costs of the respective groups would be higher than the joint costs of serving both residential and commercial customers. Proportionally, the smaller class will be allocated less of the joint costs than the larger class, while allowing both to enjoy a lower total cost for the service being provided. While the larger class contributes more to the scale economies and will receive a relatively larger share of the total economies, the equitable cost sharing results from the application of the classes' respective demands in the cost allocation process throughout the COSS.

d. Administrative and general costs?

PSE currently allocates property insurance costs on a ratebase or plant allocation factor. Other administrative and general costs are currently allocated on a salary and wage method. PSE finds this to be a satisfactory methodology to accomplish this allocation, but would be open to discussing reasoned alternative methodologies.

Avista currently identifies administrative and general (A&G) costs that can be directly associated with production, transmission, distribution or customer service functions in order to allocate them by the relevant plant assignment or number of customers. The remaining A&G costs are allocated by either non-resource operating and maintenance expenses, plant in service totals or salary and wage expense totals. Avista prefers to continue the functional assignment of A&G costs to the extent possible, however would be open to alternative methodologies regarding all functionally common A&G costs.

Pacific Power allocated most administrative and general expenses to plant in its last general rate case.

e. Poles, conductors, and line transformers?

See answer to 3(a) above under distribution assets.

4. Are there any other costs that cost of service studies should classify and allocated in a specific way?

PSE currently allocates Federal Income Tax on ratebase and finds this to be a satisfactory methodology to accomplish this allocation

<u>Questions affecting natural gas service only:</u>

1. Should the Commission adopt rules requiring marginal cost of service studies for special contract customers that rely upon a utility for natural gas interstate pipeline connections, localized distribution, or a sub-set of these components?

The Commission's rules specify the requirements for eligibility for a special contract and the necessary underlying cost support for a special contract, which is primarily focused on the incremental cost to serve the customer and the costs related to the potential by-pass of the utility's distribution system by that customer, for which a special contract is requested. A revisiting of this cost support should only be made upon a revision to the terms and conditions of the existing special contract or at the expiration of the initial term of the special contract whereby a renewal of the existing special contract or a new special contract is requested on behalf of the customer.

a. To what extent should these contracts be subject to scrutiny regarding the impact on other customers of the cost assignment to special contracts?

Including special contracts as a separate class for purposes of the embedded COSS as part of a general rate case would provide useful information as to the rate of return performance of this group of customers vis-à-vis the remaining customer classes; and therefore, the extent to which special contract customers' revenues are contributing to system costs recovery to the benefit of all other customers. The Commission should ensure that any consideration that would require revisions to the terms of the agreement, not occur during the contract term.

2. How should cost of service studies allocate demand and throughput?

The Gas Parties request clarification on this question as it is confusing. PSE suggests allocating throughput on the basis of throughput, and allocating demand-related costs on actual or planning peaks. Actual peaks can be determined in a number of ways. Cascade supports allocating demand on design day demand. Demand and energy are two of the three primary cost drivers, the third being customer-related.

a. Is a single method or a set of methods the most balanced and fair to all parties involved?

It is unlikely that a single cost allocation method will be considered the most balanced or fair by <u>all</u> parties involved, based on the specific interests of their respective constituencies. The Gas Parties encourage the Commission to continue to allow differences in methodology.

b. Should the Commission establish a preference for a particular method?

Based on the Commission's directive in Docket UE-160228 that established this generic proceeding, its stated intent was to "establish greater clarity and some degree of uniformity in COSSs going forward." Presumably that intent included establishing clarity with respect to COS methodologies accepted or preferred by the Commission. With this understanding, the Gas Parties would encourage the Commission to continue to accept and allow for differences in methodologies between utilities, as these differences can be the result of a history of the unique constituencies and circumstances.

c. Are there specific methods that should not be considered by the Commission? For what reason should the Commission not consider specific methods?

This generic proceeding provides an opportunity for the Commission to evaluate a range of cost allocation methodologies based on cost causation criteria and other potential policy considerations, as presented to them by the various parties to the proceeding. Therefore, excluding a particular cost allocation methodology from the Commission's consideration would be presumptive and inappropriate.

3. How should a cost of service study address the allocation of mains?

Below is a response from each party to this question. Each party has an approach to the allocation of mains that is developed through historical considerations appropriate to its system. The Gas Parties would advocate that the Commission consider and continue to support the differences in approach requested by each of the utilities.

Cascade Natural Gas

It is widely accepted that distribution mains (FERC Account 376) are installed to meet both system peak period load requirements and to connect customers to the gas distribution utility's system. Therefore, to ensure that the rate classes that cause the utility to incur this plant investment or expense are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and number of customers.

There are two cost causation factors that influence the level of distribution mains facilities installed by a utility in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the utility's gas system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the utility.

Two of the more commonly accepted literary references relied upon when preparing embedded COSSs, Electric Utility Cost Allocation Manual, by John J. Doran et al, NARUC, and Gas Rate Fundamentals, American Gas Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities.

A customer component of utility distribution facilities is consistent with public utility accounting theory. As Dr. James Suelflow writes in his treatise, Public Utility Accounting: Theory and Practice: "… distribution transformers and primary and secondary lines including conductors and devices (account 365 "Distribution Plant") and poles and towers (account 364 "Distribution"), all contain capacity and customer costs."[1] Dr. Suelfow recognizes that costs are more closely related to customers the closer one approaches the ultimate customer's premises.

From an overall regulatory perspective, in its publication entitled, Gas Rate Design Manual, NARUC presents a section which describes the zero-intercept approach as a minimum system method to be used when identifying and quantifying a customer cost component of distribution mains investment. Clearly, the existence and utilization of a customer component of distribution facilities, specifically for gas distribution mains, is a fully supportable and commonly used approach in the natural gas utility industry.

For a gas distribution utility, the allocation of the demand-related cost of distribution mains on the basis of the utility's system capacity planning criteria, that is, the coincident peak demand of its firm customer classes under design weather conditions, best reflects cost causation.

Puget Sound Energy

PSE currently uses a peak and average methodology to allocate main distribution costs. In PSE's 2017 GRC (UG-170034) main distribution costs were allocated approximately 67 percent based on design day peak and 33 percent based on average throughput. PSE finds this to be a satisfactory methodology to accomplish this allocation, but would be open to a discussion on reasonable alternative methodologies.

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[1] *Public Utility Accounting: Theory and Practice,* Dr. James Suelflow, Institute of Public Utilities, Michigan State University, p. 241.

NW Natural

In its most recent rate case in 2008, NWN used a peak and average methodology to allocate main distribution costs. NWN believes that method is reasonable, but is open to discuss other alternative methods.

Avista

Avista currently uses a peak and average methodology to allocate main distribution costs. Distribution mains are allocated between demand and throughput based on the system load factor. Avista finds this to be a balanced methodology that reflects how the system is designed (to meet peak demand) and the way it is utilized on an annual basis (throughput based on gas usage that occurs during all conditions, not only peak conditions), but would be open to a discussion on reasonable alternative methodologies.

a. What is the appropriate balance of demand with throughput?

Cascade Natural Gas

Throughput is not a cost causative factor underlying the capacity costs of gas distribution mains; therefore, it should not be included as a cost-based allocation basis for mains.

Puget Sound Energy

PSE uses the gas system load factor for the test year to determine this balance and finds this to be a reasonable approach, and would be open to other reasoned approaches.

NW Natural

NWN determines the share of mains costs to be allocated by peak versus average by using the load factor for the system.

Avista

Avista uses the gas system load factor for the test year to determine the split between demand and throughput. Avista finds this to be a reasonable approach, and would be open to other reasoned approaches.

b. Is it appropriate for the Commission to establish or allow different companies to use different methods?

Yes, the Commission should retain the flexibility to do so, based on the specific cost considerations, as supported by a particular utility.

c. Should the Commission allow a cost of service study to exempt specific customer classes from an identified methodology?

For certain costs that can be specifically identified with customers in a certain class, direct assignment of those costs to the class should replace or “exempt” an otherwise identified methodology.

4. How should cost of service studies classify and allocate:

a. Common and joint costs?

For definitional purposes, <u>Common</u> costs occur when the fixed costs of providing service to one or more classes or the cost of providing multiple products or services to the same class use the same facilities and the use by one class precludes the use by another class. <u>Joint</u> costs occur when two or more products or services are produced simultaneously by the same facilities in fixed proportions.

It is the existence of common costs (the primary characteristic of utility costs) that requires the cost allocation study. The need to allocate costs for ratemaking requires that cost studies be based on sound principles and that they reflect the planning and operating realities of the utility. Since no two utilities are exactly alike, there is no one best allocation methodology that may be applied as a one size fits all method. Further, systems are not static and the optimal allocation methodology may change over time as the system configuration, loads and markets change. Rather, there is a best cost allocation method for each application that reflects how the utility is planned and operated currently. That method must be chosen based on the underlying facts. Cost causation is one such basis for assessing the best cost study for allocating common costs.

Each group or class of customers share in the benefits of the presence of joint costs and economies of scale in proportion to their contribution to scale economies based on their own relative costs on a stand-alone basis. For example, for residential and commercial customers served from the same distribution system, the sum of the stand-alone costs of the respective groups would be higher than the joint costs of serving both residential and commercial customers. Proportionally, the smaller class will be allocated less of the joint costs than the larger class, while allowing both to enjoy a lower total cost for the service being provided. While the larger class contributes more to the scale economies and will receive a relatively larger share of the total economies, the equitable cost sharing results from the application of the classes' respective demands in the cost allocation process throughout the COSS.

b. Administrative and general costs?

Generally the utilities allocate the various accounts using similar allocation methods but there may be some subtle differences of which factors are used based on each utilities unique circumstance. The Gas Parties would be open to discussing reasoned common rules for allocating these costs.

5. Are there any other costs that cost of service studies should classify and allocate in a specific way?

The use of direct assignment of certain gas distribution system costs should be employed where possible, as described below.

The term "direct assignment" relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a COSS, the cost analyst seeks to maximize the amount of plant and expense directly assigned to specific customer groups to avoid the need to rely upon other more generalized allocation methods.

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