Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Yohannes K.G. Mariam. My business address is Chandler Plaza Building, 1300 South Evergreen Park Drive SW, Olympia, Washington, 98504-7250.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Washington Utilities and Transportation Commission (WUTC) as a Utility Rate Research Specialist (Economist) in the Gas Section.

Q. HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. On June 21, 2000 I submitted written testimony addressing Staff's weather normalization adjustment and its impact on revenue.

PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to review Northwest Natural Gas Company's (Company) cost of service study, and to present Staff's recommendation on the same. In addition, I present the impacts of Staff's proposed revenue requirements (as presented by Mr. James Russell), and Staff's proposed system load allocator and average peak day load allocator on rates of return of residential, commercial, and industrial customers.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I present Exhibit ___ (YKGM-3). The exhibit contains 12 tables. The descriptions are as follows:

Table 1a: Degree Days Heating, City Gate Throughputs and Number of Customers

Table 1b: Calculation of Average DDH and City Gate Throughputs

Table 2: Data Used to Perform Statistical Analysis of Relationship Between Gas Usage and Degree Days Heating (DDH)

Table 3: Results of Statistical Analysis of Relationship Between Gas Usage and Degree Days Heating

Table 4: Results of Average Contribution of Each Schedule to Daily Peak Load

Table 5a: Income and Rate of Return at Present Rates

Table 5b: Income and Rate of Return at Proposed Rates

Table 5c: Comparison of Rate Base, Rate of Return and Revenue Requirements at Present and Proposed Rates between Staff's and Company's Proposal

Table 6: Total Operation and Maintenance Expenses

Table 7: Total Net Rate Base

Table 8: Plant in Service

Table 9: Total Functionalized Revenue Requirements to be Recovered in Rates at Present Rates of Return

Table 10: Total Revenue Requirements at Proposed Rates of Return

Table 11: Unit Cost Summary at Proposed Rates of Return

Table 12: Unit Cost Summary at Equalized Proposed Rates of Return

I will refer to these tables throughout my testimony.

COST OF SERVICE

Q. WHAT IS A COST OF SERVICE STUDY?

A. A cost of service study is a detailed and comprehensive economic, engineering, and accounting study that allocates the total cost of providing service to various classes of customers. It measures the utility's costs incurred to serve each class of customer, including a reasonable return on investment for a specified period of time.

Q. PLEASE DESCRIBE HOW A COST OF SERVICE STUDY IS IMPLEMENTED AND ITS PURPOSE IN A GENERAL RATE CASE FILING BY A UTILITY COMPANY.

A. The implementation of a fully allocated or embedded cost of service study involves a three-step approach: functionalization, classification, and allocation. In the first step, total costs (rate base, or investment, and expense items) of a utility, as maintained in accordance with the FERC's Uniform Systems of Accounts, are assigned to four cost functions with which they are closely associated: production, storage, transmission, and distribution. In the second step of the cost of service study, classification, each

functional cost is further divided by cost-causation. There are four categories or classes that are related to measurable cost-defining characteristics of providing gas service: demand (capacity), commodity (energy), customer, and revenue. Once the functionalized costs are classified into cost-causing categories, the final step of the cost of service study, allocation, develops factors that are used to allocate costs to classes of customers or rate schedules. Often, the development of allocation factors is based on usage and customer information associated with the test period results of operations.

The cost of service study enables the analyst to determine whether or not the revenue provided by a class of customers recovers the cost to serve those customers. The results of the cost of service study are used in assessing the appropriateness of rate spreads across classes of customers.

Q. HOW DID THE COMPANY IMPLEMENT THE FUNCTIONALIZATION STEP OF ITS COST OF SERVICE STUDY?

A. The functionalization of investment and expense items is the easiest step in a cost of service study. Investment and expense records of the Company are maintained in accordance with the FERC's Uniform Systems of Accounts that categorizes costs according to primary operating functions. Therefore, the Company has used a universally accepted method of functionalizing costs.

Q. DO YOU AGREE WITH THE METHOD EMPLOYED BY THE COMPANY IN CLASSIFYING COSTS AS DEMAND, ENERGY, CUSTOMER AND REVENUE-RELATED?

A. To a large extent, the Company utilized a classification method accepted in the literature as well as in past Commission-approved cost of service studies (e.g., Docket No. UG-940814, concerning Washington Natural Gas Company). However, I do not agree with the classification of mains and main-related items into demand and energy. I will discuss this disagreement in more detail in my testimony concerning allocation.

Q. DO YOU DISAGREE WITH ANY OF THE ALLOCATORS PROPOSED BY THE COMPANY?

A. Yes. I do not agree with the method employed by the Company to derive the system load factors used to allocate mains and main-related costs into demand (capacity) and commodity components (system load factors). Furthermore, I disagree with the method employed to calculate each schedule's contribution to peak loads. The method employed by the Company in order to determine system load factors is a version of the "Peak and Average" method.

Q. GENERALLY SPEAKING, HOW IS THE PEAK AND AVERAGE METHOD IMPLEMENTED?

A. Costs are classified between demand and commodity components based on a company's annual load factor. Then, the demand-related costs are allocated to the different classes of customers using each rate schedule's contribution to peak demand. The commodity-related costs are allocated according to each rate schedule's normalized annual throughputs or volumes. This approach is consistent with Commission's prior orders, and with the manner in which the Company's distribution system should be utilized. That is, some portion of the fixed cost related to the distribution of gas (or mains-related costs) should be allocated to reflect the fact that the system is built to deliver gas year round, as opposed to assuming that distribution-related fixed costs are incurred solely for peak gas delivery.

Peak load is significantly influenced by the composition of classes of customers and temperature. In most situations, however, temperature is the most important factor determining peak load. In most general rate cases, rates approved by the Commission are likely to remain unchanged for more than a year. Therefore, an historic average of the coldest days or the corresponding peak day volumes should be used to determine peak daily loads. In recognition of this fact, previous rate cases have used an historic average of five days per year over the most recent three years (a total of 15 observations) to calculate the demand and commodity components (system load factors) of mains and main-related costs, and the contribution of each class of

customers to the system peak load. The Commission approved this three-year historic average method in Docket Nos. U-89-3105 (WWP) and UG-940814 (WNG), and rejected cost allocation based on a single peak day in Docket No. UG-901459 (WWP).

Q. WHAT METHOD IS USED BY THE COMPANY TO DERIVE SYSTEM LOAD FACTORS TO ALLOCATE MAINS-RELATED COSTS INTO DEMAND AND COMMODITY COMPONENTS?

A. The Company used a version of the "Peak and Average Method" to determine the system load factors. Rather than using an historic average of five days from three years data, the Company calculated the average volumes of the five coldest days from the most recent three years. The selected five coldest days were in 1998. This kind of selection of peak days is similar to that of a design peak day, rather than a historic average.

Q. SHOULD THE COMMISSION ACCEPT THE COMPANY'S PEAK AND AVERAGE APPROACH?

No, it should not. The approach used by the Company does not utilize an appropriate statistical method to estimate the impact of weather on each rate schedule's gas usage. Furthermore, the Company's method does not ensure that the average degree days heating (DDH) used in determining estimated peak day gas usage is representative of the coldest five days observed in each of the most recent three years. The method

implemented by the Company is also different from the peak and average method approved by the Commission for Washington Natural Gas in Docket No. UG-940814.

Q. PLEASE EXPLAIN IN MORE DETAIL WHY THE COMPANY'S VERSION OF THE PEAK AND AVERAGE METHOD SHOULD BE REJECTED.

A. The majority of customers in the Company's Washington service territory are residential. Thus, the composition of customers could be viewed as relatively homogenous. Therefore, the system peak load would be heavily impacted by changes in weather. Average degree days based on extreme weather, as observed in the Company's case cannot be taken as representative of what may hold true with respect to the magnitude of system load factors or factors used to allocate each schedule's contribution to peak load. Testimony filed by the Company indicates that the peak day throughput is an average of the five highest volume days in the last three years. However, the peak and average method is expected to use the five highest volume (coldest) days from each of the most recent three years in calculating the contribution of each rate schedule to average daily peak load and system load factors. This method is empirically superior and plausible because it is based on an historic average of weather and load, rather than an average based on five observations from a single year.

Q. PLEASE DESCRIBE THE SPECIFIC METHOD THE COMPANY USED TO DETERMINE SYSTEM LOAD FACTOR AND EACH SCHEDULE'S CONTRIBUTION TO PEAK DAY GAS USAGE.

A. Examination of the Company's response to NWIGU Data Request No. 28 revealed that statistical regressions were used to estimate gas usage per degree day heating (DDH) for all but Schedules 55, 61 and 90. The coefficients from the regression analyses were multiplied by the number of customers and the five highest DDH per day over the most recent three years. Finally, an average volume was computed for the five coldest days, rather than an average from the five coldest days in each of the most recent three years.

Q. PLEASE DESCRIBE STAFF'S PROPOSED CHANGE TO THE METHOD OF CALCULATING THE SYSTEM LOAD FACTORS AND EACH SCHEDULE'S CONTRIBUTION TO PEAK DAY GAS USAGE OR LOAD.

A. The implementation of the peak and average method is used, first, to determine the system load factor (commodity) and demand (capacity) factor and, second, to facilitate the allocation of peak day gas usage among the various rate schedules. The steps followed by Staff to implement the peak and average method are as follows.

First, the annual throughput for the test year was calculated from each rate schedule's test year annual throughput. The annual throughput was then divided by 365 to determine the system average daily gas usage.

Second, degree days heating and the corresponding city gate throughput were gathered for the five coldest days in each of the most recent three years. The five coldest days (highest DDH) and the corresponding five actual city gate throughputs over each of the recent three years were ranked in ascending order by DDH, and their average calculated. Thus, Staff replaced the five days DDHs used by the Company by a historic average of five coldest days and average city gate throughputs from each of the most recent three years (Tables 1a and 1b).

Third, Company data on gas usage and DDH were used to perform a regression analysis (Table 2). An appropriate statistical estimation method was then used to calculate each schedule's heat (weather sensitive) and base (non-weather sensitive) use of gas (Table 3). Staff does not agree with the Company's statistical estimation procedure because the Company's method did not take into account issues related to correlation between regression residual of consecutive observations, as noted in my prior testimony on weather normalization.

Fourth, the total estimated gas usage (i.e., the sum of the estimated weather sensitive and non-weather sensitive gas usage) for each rate schedule for each of the average five coldest days (as described in step 2 above) was calculated using the coefficients from Staff's regression analysis (Table 3). The number of customers used in calculating the total estimated gas usage is the same as the test year customers of each rate schedule. The Company used the number of customers that correspond to the coldest degree days in 1998. However, Staff used test year customers in each class

as filed by the Company in order to calculate average peak day loads (Table 1b). The reason for this choice of test year customers was that the total number of customers served by the Company is expected to increase. Also, correlation analysis of city gate throughputs, DDH, and number of customers for the five coldest days observed in each of the last three years indicated that the number of customers is not significantly correlated with city gate throughputs, but the latter is significantly correlated with DDH. Finally, the ratio of each schedule's gas usage to each of the five average actual city gate throughput and five average coldest days (as described in step 2) was calculated.

Fifth, each of the average five actual total city gate throughputs corresponding to each of the average five coldest days (as described in step 2) was allocated to each rate schedule based on the ratio of each schedule's estimated gas usage to total estimated gas usage (as described in step 4, and see Table 4). The average peak day load of each rate schedule was calculated from each schedule's contribution to the average five city gate throughputs corresponding to each of the average five coldest days (described in step 2). The sum of average peak load of each rate schedule (that is, the average city gate throughputs from each of the five coldest days from each of the recent three years) will result in the system average daily peak load. The ratio of each schedule's contribution to the system average peak load was used to allocate the demand component of mains-related costs, also called the "peak day allocator."

Sixth, the ratio of the system average daily gas use (as described in step 1) to the sum of the contribution of each rate schedule to system average daily peak load (as described in step 5) was calculated to determine the system load factor. The balance (100% minus the load factor) is the demand or capacity factor. These factors were used to classify primary mains-related costs into commodity and demand components. In addition, the load factor derived in this step was used to allocate the demand and energy components of costs related to primary mains to classes of customers served by these mains.

Seventh, the same procedure as in step six was employed by excluding special contracts. The resulting factors were used to classify secondary mains related costs into commodity and demand components. Furthermore, the load factor derived from this step was used to allocate the demand and energy component of costs related to secondary mains to classes of customers served by these mains.

The method used by Staff is superior to the method used by the Company because it recognizes variability in weather and volume and the potential for growth in customers. The Company's method, on the other hand, assumes that the coldest days observed in 1998, and the 1998 volume and number of customers, would prevail in the future. Staff strongly disagrees with the approach used by the Company.

Q. PLEASE DESCRIBE WHAT OTHER MODIFICATIONS YOU MADE TO THE INPUTS TO THE COST OF SERVICE STUDY.

A. I incorporated the proposed revenue requirements and gas costs as testified by Mr. James Russell.

Q. PLEASE DESCRIBE THE IMPACT OF STAFF'S PROPOSED CHANGES ON THE RATES OF RETURN FOR EACH CLASS OF CUSTOMER SERVED BY THE COMPANY.

A. The impacts on rate of return at present and proposed rates of incorporating Staff's system load allocator and each schedule's contribution to average daily peak load are presented in Tables 5a and 5b of Exhibit ___ (YKGM-3). A summary of Tables 5a and 5b is also shown in Table 5c. As seen from Table 5c, the overall rate of return at present rates (assuming a unitized rate of return) increased by 67%, 33%, and 14% for residential, commercial, and high volume (industrial) customers, respectively. The rate of return at proposed rates was calculated and compared to the rate of return filed by the Company. The result shows that the rate of return at proposed rates increased by 16% for residential customers, and reduced by 9% and 36% for commercial and industrial customers, respectively (Table 5c). Analysis of rates of return of each rate schedule indicates that commercial customers are paying more than their share of total costs, while residential and high volume customers are recovering about 80% of the costs incurred to provide natural gas service to them.

Q. PLEASE EXPLAIN THE RESULTS PRESENTED IN TABLES 6 TO 12 OF YOUR EXHIBIT.

A. Tables 6, 7, and 8, respectively, show the allocation of total operation and maintenance expenses, total net rate base, and plant in service by rate schedule after incorporating Staff's proposed changes with respect to revenue requirements, and system and peak load allocators. Tables 9 and 10 present total revenue requirements by rate schedule at present and proposed rates of return, respectively. Finally, Tables 11 and 12 show unit cost summary at proposed rates of return and at equalized proposed rates of return, respectively.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.