STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

NORTH SHORE GAS COMPANY	:	
	:	No. 07-____
Proposed General Increase	:	
In Rates For Gas Service	:	

Direct Testimony of

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Director
Navigant Consulting, Inc.

On Behalf of
North Shore Gas Company

March 9, 2007

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I. INTRODUCTION AND WITNESS QUALIFICATIONS

A. Identification of Witness

Q. Please state your name and business address.

A. My name is Ronald J. Amen. My business address is 175 W. Jackson, 5th floor, Chicago, Illinois, 60604.

Q. Mr. Amen, by whom are you employed and in what capacity?

A. I am a Director with Navigant Consulting, Inc. ("NCI") and a member of the Regulatory Advisory and Litigation Support Practice Area of the Firm. NCI is a leading nationwide provider of consulting services to electric and gas utilities and other energy-related and network businesses.

B. Purposes of Testimony

Q. What are the purposes of your direct testimony in this proceeding?

A. The purposes of my direct testimony are to:

(1) Present and explain the preparation and results of North Shore Gas Company's ("North Shore Gas'") embedded cost of service study ("ECOSS"), which comprises North Shore Exhibit RJA – 1.1 through Exhibit RJA – 1.10.

(2) Describe the full-cost level of revenue responsibility between customer classes as a result of the revenue requirement proposed by North Shore Gas in this proceeding and supported by the ECOSS.

North Shore Gas' witness Ms. Grace (North Shore Exhibit ("Ex.") VG-1.0) will use the results of the ECOSS to discuss proposed changes in the North Shore Gas rate schedules through which it seeks to recover its base rate revenue requirement (the portion of its revenue requirement to be recovered through the base rates to be established in this case).

C. Summary of Conclusions

Q. Please summarize the fundamental conclusions to be drawn from the results of the ECOSS, as presented in your direct testimony.

A. The results of the ECOSS show the distribution of revenue responsibility by customer class necessary to achieve equalized rates of return on investment by customer class at North Shore Gas' proposed revenue requirement, that is, an equitable level of cost recovery from the respective customer classes. In addition, certain adjustments could be made to the rate components of the various rate schedules in order to more clearly match customer cost responsibility with cost causation of the costs on the utility system.

D. Itemized Attachments to Direct Testimony

Q. Are you sponsoring any attachments to your direct testimony?

A. Yes. I am sponsoring, and have attached hereto, the following exhibits:

- North Shore Ex. RJA – 1.1 — Embedded Class Cost of Service Study Summary
- North Shore Ex. RJA – 1.2 — Functionalized Rate Base, Revenue Requirement and Unit Costs
- North Shore Ex. RJA – 1.3 — Detailed Cost of Service Study Results
- North Shore Ex. RJA – 1.4 — Allocation Factors
- North Shore Ex. RJA – 1.5 — Class Load and Service Characteristics of the Company's Customers
- North Shore Ex. RJA – 1.6 — Graph of Relationship between Footage of Mains and Number of Customers
- North Shore Ex. RJA – 1.7 — Embedded Class Cost of Service Study Summary Schedules (Revenue Requirement including Gas Cost Related Uncollectible Expense)

- North Shore Ex. RJA – 1.8 — Comparison of Embedded Class Cost of Service Study Results under Alternative Methodologies
- North Shore Ex. RJA – 1.9 — Alternative Embedded Class Cost of Service Study Summary Schedules under Peak with Customer Component Methodology
- North Shore Ex. RJA – 1.10 — Alternative Embedded Class Cost of Service Study Summary Schedules under Average and Peak Methodology
- North Shore Ex. RJA – 1.11 — Curriculum Vitae of Ronald J. Amen

Q. Please briefly describe the first four exhibits attached to your testimony.

A. North Shore Ex. RJA – 1.1 presents the following revenue requirement and rate of return summary results of North Shore Gas' ECOSS:

- Earned Return Summary at Present Rates
- Revenue Requirement at Equalized Rates of Return
- Proposed Revenue Requirement and Rate of Return by Service Classification

North Shore Ex. RJA – 1.2 presents the following summary information:

- Functionalized Rate Base at Equalized Rates of Return
- Functionalized Revenue Requirement at Equalized Rates of Return
- Unit Costs at Equalized Rates of Return

North Shore Ex. RJA – 1.3 presents all details of the Company's proposed cost of service study by Federal Energy Regulatory Commission ("FERC") primary account (the Uniform System of Accounts) by rate schedule.

Finally, North Shore Ex. RJA – 1.4 summarizes the following:

- External Classification and Allocation Factors
- Internal Allocation Factors

The external classification and allocation factors were derived from North Shore Gas' pro forma level of customers, volumes, and revenues, as well as the results of subsidiary analyses conducted by the Company related to cost causation indicators for certain plant and expense elements. The internal allocation factors are derived within the cost of service study model, consisting of subtotals and other combinations of related plant and operation and maintenance ("O&M") accounts, which are then used to allocate certain related accounts and miscellaneous, general and administrative overhead accounts.

E. Background and Experience

Q. Please describe NCI's business activities.

A. NCI is a global management consulting firm that provides strategic, financial, management, and expert services to energy-based, network and other regulated industries. From an industry-wide perspective, NCI has extensive experience in all aspects of the North American natural gas and electric industries. NCI's relevant experience is in the areas of utility costing and pricing, gas supply and transportation planning, competitive market analysis and regulatory practices and policies gained through management and operating responsibilities at transmission and distribution, gas pipeline and other energy-related companies, and through a wide variety of client assignments. NCI has assisted numerous utility companies located in the U.S. and Canada.

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

A. I have over twenty-eight (28) years of experience in the utility industry, the last ten (10) years of which have been in the field of utility management and economic consulting. Specializing in the gas industry, I have advised and assisted utility management and

energy marketers in matters pertaining to costing and pricing, regulatory planning and policy development, strategic business planning, organizational restructuring, new business development, and load research studies. Further background information summarizing my education, presentation of expert testimony and other industry-related activities is included in North Shore Ex. RJA-1.11.

Q. For what purpose have you been retained by North Shore Gas?

A. I have been retained by North Shore Gas as a consultant in the area of utility costing and related regulatory matters. Specifically, North Shore Gas has requested that I assist in conducting a cost of service study to determine the embedded costs of serving its natural gas retail customers, in addition to various costing and pricing studies related to the provision of gas distribution, transportation and storage-related services.

Q. Have you testified previously before the Illinois Commerce Commission ("the Commission" or "ICC")?

A. No, I have not.

II. NORTH SHORE GAS' PROPOSED BASE RATE REVENUE REQUIREMENT

Q. What total gas revenue requirement, to be recovered through the base rates to be established in this proceeding, is North Shore Gas utilizing in its proposal?

A. North Shore Gas has used a proposed total revenue requirement with Rider UBA for purposes of determining base rate revenues of $65,771,714, net of other operating revenues of $1,755,286. These revenue credits of $1,755,286 consist of miscellaneous revenue items such as: forfeited discounts, miscellaneous service and other revenues. The total proposed revenue requirement of $65,771,714, including the proposed rate

increase of $4,651,000 appears in the cost of service summary schedule, Ex. RJA – 1.1, on Page 1, column B, line 30. The total revenue requirement at proposed rates of $$65,772,000 is shown on Page 1, column B, line 36, of the exhibit.

Q. What is the total gas revenue requirement to be recovered through base rates without Rider UBA?

A. The proposed total revenue requirement without Rider UBA for purposes of determining base rate revenues is $67,313,714, net of other operating revenues of $1,755,286. The total proposed revenue requirement of $67,313,714, including the proposed rate increase of $6,193,000 appears in the cost of service summary schedule in Ex. RJA – 1.7, on Page 1, column B, line 30. The total revenue requirement at proposed rates of $67,314,000 is shown on Page 1, column B, line 36, of the exhibit.

III. PURPOSE OF AN ECOSS

Q. What is an ECOSS?

A. An ECOSS is an analysis of costs which assigns to each customer or rate class its proportionate share of the utility's total cost of service, i.e., the utility's total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

Q. What is the purpose of an ECOSS?

A. The purpose of an ECOSS is to determine what costs are incurred to serve the various classes of customers of the utility. When these costs are all tabulated, the rate of return that is provided by each class of service of the utility can be determined. This resulting

rate of return will be impacted by the cost allocation of the methodology employed. The ECOSS is a tool that the analyst uses to assist in determining revenue responsibility by rate class and rate design. The results of the ECOSS will provide the analyst with the data necessary to design cost-based rates.

IV. PRINCIPLES OF AN ECOSS PREPARATION

Q. What is the guiding principle that should be followed when performing an ECOSS?

A. C*ost causation* is the fundamental principle applicable to all cost studies for purposes of allocating costs to customer classes. Cost causation addresses the question, which customer or classes of customers causes the utility to incur particular types of costs? In order to answer this question, it is necessary to establish a relationship between a utility's customers and the particular costs incurred by the utility in serving those customers.

Q. What is the general framework of an ECOSS?

A. As I indicated above, the ECOSS analysis is intended to establish cost responsibility among the various customer classes which the utility serves. The analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes. As stated above, the most important theoretical principle underlying an ECOSS is that cost incurrence should follow cost causation. In other words, the costs that customers become responsible to pay should be those costs that the particular customers caused the utility to incur because of the characteristics of the customer's usage of utility service.

Q. What are the steps to performing an ECOSS?

A. In order to establish the cost responsibility of each customer class, initially a three step analysis of the utility's total operating costs must be undertaken. The three steps which are the predicate for an ECOSS are: (1) cost functionalization; (2) cost classification and (3) cost allocation of all the costs of the utility's system.

Q. Please describe cost functionalization.

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. North Shore Gas' functional cost categories associated with gas service include: Production, Storage, Transmission, Distribution, and Customer Accounts and Sales.

Q. Please describe cost classification.

A. Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost defining characteristics of: (1) customer related; (2) demand or capacity related; and (3) commodity related.

Q. Please describe cost allocation.

A. The final step is the allocation of each functionalized and classified cost element to the individual customer or rate class. Costs typically are allocated on customer, demand, and commodity allocation factors.

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

A. Yes. The factors which can influence the cost allocation used to perform an ECOSS include: (1) the physical configuration of the utility's gas system; (2) the availability of

data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q. Why are these considerations relevant to conducting North Shore Gas' ECOSS?

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

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

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

Q. What are the specific physical characteristics of the North Shore Gas' system?

A. As Mr. Doerk testifies, the physical configuration of the North Shore Gas' system is a dispersed / multiple city-gate, integrated transmission / distribution and multi pressure-based system.

Q. How does the availability of data influence an ECOSS?

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

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

A. State regulatory policies and requirements prescribe whether there is a particular approach historically used to establish utility rates in the state. Specifically, state regulations set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the particular cost allocation method utilized by the utility. In some instances, this Commission has expressed a preference for a utility to utilize a costing methodology that 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.

V. <u>ECOSS COST ALLOCATION</u>

Q. How is the concept of cost causation, discussed earlier, applied to the evaluation of the utility's transmission and distribution system?

A. There are three basic components in gas utility operations which govern cost behavior. These are: (1) extending distribution services to all customers entitled to be attached to the system; (2) meeting the aggregate design day capacity requirements of all customers entitled to service on the peak day; and (3) delivering volumes of natural gas to all customers either on a sales or transportation basis. These operational components have

been identified for purposes of the ECOSS as Customer Costs, Demand Costs, and Commodity Costs, respectively.

Q. Please explain.

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

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

Commodity Costs are those costs that vary with the throughput sold to, or transported for, customers. For example, included in the instant study are commodity related costs such as compressor fuel, underground storage inventory or "top gas", and fuel related to storage injections or withdrawals. However, when, as here, a gas utility's cost of gas is not recovered through its base rates, very little of its remaining delivery service cost structure is commodity related.

Q. How does the cost analyst establish the cost and utility service relationships?

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

Q. Please explain the term "direct assignment."

A. The term "direct assignment" means the allocation to a specific customer or class of customers based on that customer's or class' exclusive identification with the particular plant or expense at issue. Usually costs that are directly assigned relate to costs incurred exclusively to serve a specific customer or class of customers. Direct assignments best reflect the cost causative characteristics of serving individual customers or classes of customers. Therefore, in performing an ECOSS, the cost analyst seeks to maximize the amount of plant and expense directly assigned to a particular customer or customer class to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by a special study as is done with costs associated with meters and services.

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

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

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

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

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

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

Q. Please explain the considerations relied upon in determining the cost allocation methodologies that are used to perform an ECOSS.

A. As stated above, in order to allocate costs within any cost of service study, the factors that cause the costs to be incurred must be identified and understood. Additionally, the cost analyst needs to develop data in a form that is compatible with and supportive of rate design proposals. The availability of data for use in developing alternative cost allocation factors is also a consideration. In evaluating any cost allocation methodology,

appropriate consideration should be given to whether it provides a sound rationale or theoretical basis, whether the results reflect cost causation and are representative of the costs of serving different types of customers, as well as the stability of the results over time.

Q. Please describe the key issues related to the allocation of demand-related costs within an ECOSS.

A. A complex part of the allocation process is the allocation of demand costs. Several methodologies have been used by gas utilities to develop allocation factors for the demand components of costs. It is not unusual for more than one demand cost allocation approach to be used in a cost of service study. Despite the use of different methodologies to allocate demand costs, there are three basic methodologies that form the foundation for the allocation process. These basic three methodologies are Peak Demand Allocations, Average and Excess Demand Allocations, and Non-Coincident Demand Allocations. Each of these demand allocation methodologies is discussed in greater detail below.

Q. Please describe those three methodologies in greater detail.

A. The concept of Peak Demand Allocation is premised on the notion that investment in capacity is determined by the peak load(s) of the utility. Under this methodology, demand related costs are allocated to each customer class in proportion to the demand coincident with the system peak of that customer class. The Peak Demand Allocation process might focus on a single system peak, such as the highest daily demand occurring during the test period. Alternatively, it might include the average of several cold days, either consecutive or occurring over a period of several years, or it could be the expected

contribution to the system peak under weather conditions for which the system was designed to serve, commonly referred to as a "design day."

The Average and Excess Demand Allocation methodology, also referred to as the "used and unused capacity" method, allocates demand related costs to the classes of service on the basis of system and class load factor characteristics. Specifically, the portion of utility facilities and related expenses required to service the average load is allocated on the basis of each class' average demand and is derived by multiplying the total demand related costs by the utility's system load factor. The remaining demand related costs are allocated to the classes based on each class' excess or unused demand, i.e., total class non-coincident demand minus average demand.

A simplified version of this methodology is the Average and Peak methodology. This cost methodology often gives equivalent weight to peak demands and average demands. As is the case with the Average and Excess method, it has the effect of allocating a portion of the utility's capacity costs on a commodity-related basis.

The Non-Coincident Demand Allocation methodology recognizes that certain facilities, in particular distribution facilities, are designed to serve local peaks, which may or may not be coincident with the system peak loads. Using this methodology, demand costs are allocated on the basis of each rate class' maximum demand, irrespective of the time of the system peak.

Q. As stated earlier, the load characteristics of a utility's customers are an important element in determining the costs incurred by the utility in serving its customers. Have the load characteristics of the North Shore Gas' customers been summarized?

A. Yes. The relevant load characteristics of North Shore Gas' various customer groups are shown in North Shore Ex. RJA – 1.5. In reviewing this information, it is important to point out that for each class of service, the absolute and relative level of certain of these load characteristics have a direct influence on the type and level of costs incurred by North Shore Gas in serving its customers.

Q. What are the implications of class load characteristics for purposes of determining the costs to serve a utility's customers?

A. Annual load factor is an important indicator of how a customer utilizes a utility's distribution pipeline capacity. As a customer's annual load factor increases, it indicates that the customer is using the utility's system capacity more efficiently than a lower load factor customer. In addition, peak day demand is a key element in the sizing of a utility's facilities and in determining the level of costs incurred in serving its customers. The day-to-day utilization of a utility's facilities by its customers is measured by their annual gas consumption characteristics. Each of these characteristics can be a factor in any ultimate determination of the nature and extent of the allocation costs to a customer or customer class.

VI. <u>NORTH SHORE GAS' ECOSS</u>

Q. What is the source of the cost data analyzed in North Shore Gas' ECOSS?

A. All cost of service data have been extracted from the Company's total cost of service (*i.e.*, base rate revenue requirement) contained in the instant general rate case filing. Where more detailed information was required to perform various subsidiary analyses related to certain plant and expense elements, the data were derived from the historical books and records of the North Shore Gas.

Q. Did you make any changes to the classes of service included in the ECOSS you prepared compared to the cost study submitted in North Shore Gas' last general rate case proceeding?

A. No, I did not.

Q. How have the demand-related costs been allocated in North Shore Gas' proposed ECOSS?

A. A coincident peak demand allocation methodology is the approach utilized in North Shore Gas' ECOSS. This methodology is derived on a design day basis for allocating various portions of North Shore Gas' capacity related costs. Capacity costs for North Shore Gas consist of the costs associated with city-gate facilities and the capacity portion of the North Shore Gas' transmission and distribution system.

Q. Please continue.

A. Despite North Shore Gas' preference for the Coincident Peak Demand Allocation method, the ECOSS is being presented utilizing two of the alternative methodologies, *i.e.*, (1) a coincident peak method, with a portion of distribution mains classified as customer related, and (2) an Average and Peak approach, the underlying methodology adopted by the Commission in North Shore Gas' most recent general rate proceeding. Hence, North Shore Gas is presenting ECOSS results using three alternative cost of service allocation methods in this proceeding.

Q. Why has North Shore Gas chosen to present ECOSS results using three alternative methodologies?

A. As mentioned earlier, it is common for multiple cost of service allocation methodologies to be used in a cost of service study. North Shore Gas believes there is value in viewing the range of cost study results under the most commonly used approaches in the gas industry for utilities when considering the cost responsibility implications for its various customer (or rate) classes. This should not be taken to mean that North Shore Gas is indifferent to which methodology is used, or that North Shore Gas believes all methodologies have equal applicability.

Q. Please discuss in general what is illustrated by a comparison of the results utilizing the three aforementioned methodologies.

A. As discussed in more detail later in this testimony, cost of service study results reflect cost incurrence and the utility's philosophy for apportioning costs, which then provide guidelines for use in evaluating class revenue levels and rate structures. When evaluating class revenue levels, the rate of return results and resulting revenue-to-cost ratios show that rates charged to certain rate classes recover more or less than their indicated cost of service. A comparison of the results of the three allocation methodologies enhances North Shore Gas' understanding of the cost responsibility differences reflected by the application of each allocation methodology.

Q. Why is the presentation of several methodologies valuable in evaluating customer cost responsibility?

A. The parallel presentation of ECOSS results under each of the most commonly used cost of service methodologies will aid North Shore Gas and the Commission in the application of the judgment necessary in arriving at the decision concerning the adjustment of rates and class revenue responsibility. This will also permit better evaluation of the

appropriate alignment between class revenue responsibility and the cost of providing service to that customer class. By presenting the cost study results for the three alternative methodologies on a consistent basis, that is, with all other aspects of the studies unchanged, a proper comparison can be made.

Q. Why has North Shore Gas chosen to utilize a Coincident Peak Demand methodology in developing its preferred ECOSS allocation method?

A. North Shore Gas has based its proposed rates on the study results using the coincident peak allocation methodology because this demand allocation approach reflects cost causation on its system. The coincident peak demand allocation method strikes a balance between the other two illustrative methodologies, one that supports an additional cost causative principle, that being a customer related element to the distribution system, and the alternative average and peak approach, which gives recognition to system utilization characteristics.

Q. Please explain.

A. From a gas engineering perspective, it is my understanding that a peak demand design criterion is always utilized when designing a gas distribution system to accommodate the gas demand requirements of the customers served from that system, whether the investment is driven by the need to replace aging and deteriorating pipelines or for the purpose of expanding transmission or distribution capacity to serve growing demand on the system. As North Shore Gas witness Mr. Doerk discusses (North Shore Ex. ED-1.0), a utility's gas system sized only to accommodate average gas demands would be unable to accommodate system peak demands. That is, by sizing plant investment for peak period demands, the utility is assured to satisfy its service obligation throughout the year.

As such, cost causation with respect to demand related costs is unrelated to average demand characteristics.

Q. Please continue.

A. Additionally, use of average demand characteristics for the allocation of demand related costs penalizes customers that exhibit efficient gas consumption characteristics, *i.e.*, customers with high load factors, and encourages the inefficient use of the utility's gas system by customers with low load factors. Under-utilization of a utility's gas system is a result that a utility can hardly encourage, recognizing that higher system utilization will result in lower unit costs to all customers served by the utility. For the above-stated reasons, it is inappropriate to rely upon only a commodity-based allocation factor, as derived from annual gas throughput volume, for purposes of allocating demand related costs to a utility.

Q. Why did you choose to utilize North Shore Gas' design day demand rather than its actual peak day demand as a demand allocation factor?

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

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

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

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

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

A. As Mr. Doerk indicates, North Shore Gas must consistently rely upon design day demand in the design of its own distribution facilities required to service 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 North Shore Gas to acquire resources, build facilities and incur millions of dollars in fixed costs on an ongoing basis. In my opinion, there is no better way to capture the true cost causative factors of North Shore Gas' operations than to utilize its design peak day requirements within its cost of service studies.

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

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

Q. Has the Commission previously endorsed the use of a design day for allocation of peak demand-related costs?

A. Yes. My understanding is that the use of a peak day allocation method that reflects design day weather conditions is consistent with the Commission's 2002 Order in a MidAmerican Energy Company gas rate case in ICC Docket No. 01-0696, which stated in part:

> The Commission agrees with MEC that using design day ... to allocate peak-demand-related costs is the appropriate choice because it is related to the actual system as built to serve all classes of customers. The most extreme temperature experienced ... does not have that relationship … [and] is inappropriate because it would only meet, and not exceed, an already-experienced peak demand.[1]

Q. What are the results of utilizing design day as an allocator on the North Shore Gas system?

A. This method results in a peak day demand for North Shore Gas of approximately 3.6 million Mcf. The resulting demand level reflects the current gas usage characteristics by class, for the test year, fiscal 2006.

Q. Please discuss the rationale for the classification of a portion of the investment in distribution mains as customer related, which comprises one of the two alternative methodologies presented.

A. Identifying a portion of mains investment as customer related is an accepted principle throughout the gas industry. The assumption is that distribution mains (FERC Account No. 376) are installed to meet both system peak load requirements and to connect

[1] MidAmerican Energy Company, Proposed General Increase in Rates, ICC Docket No. 01-0696, order dated September 11, 2002, page 26.

customers to the utility's gas system. Therefore, to ensure that the rate classes that cause the investment in this plant are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and numbers of customers.

Q. What are the factors that affect the level of distribution mains facilities installed by a utility?

A. There are two cost 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.

Q. Is the method used to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?

A. Yes, it is. The two most commonly used methods for determining the customer cost component of distribution mains facilities are: (1) the zero-intercept approach, and; (2) the most commonly installed, minimum-sized unit of plant investment approach. Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, (1) Electric Utility Cost Allocation Manual, by John J. Doran et al., National Association of Regulatory Utility Commissioners (NARUC), and (2) 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.

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 distribution mains, is a fully supportable and commonly used approach in the gas industry.

Q. Please describe the zero-intercept method for determining a customer component of distribution mains costs.

A. Under the zero-intercept approach, which is the method utilized in one of North Shore Gas' alternative cost studies, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the utility's gas system against the actual size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the utility's distribution system, regardless of the customer's peak or annual gas consumption.

Q. Please discuss the minimum-sized unit approach.

A. The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. This method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system. While the zero-intercept method, with reliable data, estimates the customer costs associated with a zero-size pipe diameter, the minimum-size method may include some capacity costs since any minimum size pipe considered will, in fact, be capable of actually delivering some gas. In the case of North Shore Gas, this would be a 2 inch diameter distribution main.

Q. With respect to North Shore Gas' specific operating conditions, is there demonstrable evidence to support the use of a customer component of distribution mains?

A. Yes. The results of the zero intercept analysis based on North Shore Gas' investment in distribution mains of 16 inches in diameter or less can be expressed formulaically as follows (using the results for steel mains in the illustration):

$$y = mx + b$$

Where: y = average cost per installed foot of North Shore Gas' distribution mains

m = $8.90 per installed foot per inch of pipe diameter

x = diameter of distribution mains

b = $19.07 per installed foot

This equation reveals that regardless of the main's diameter, the average cost of a distribution main on North Shore Gas' gas system will be at least equal to $19.07 per installed foot. Stated differently, $19.07 of the total cost of each foot of installed main is <u>unrelated</u> to the main's diameter. The $19.07 per foot cost component is exclusively

related to the fact that North Shore Gas incurs this cost to install a main, regardless of its size, *i.e.*, the installation is unrelated to either peak gas flows or average gas flows. Furthermore, these disaggregated costs are related more strongly to the process of extending the distribution mains to connect customers, which is a function of the length of distribution mains and not of the size or diameter of the mains. This is the per foot customer cost component of North Shore Gas' distribution mains as distinguished from the per foot demand cost component, which is equal to $8.90 per foot times the diameter of the distribution main.

Q. Why did you select mains sized between 2 to 16 inches in diameter for the zero intercept analysis?

A. Mains within this size range comprised North Shore Gas' distribution grid, from which customer service connections are made. Larger diameter mains generally operate at higher pressures and serve a transmission or high pressure backbone distribution function, that is, they are designed with the capacity to move large volumes of gas under peak weather conditions from interstate pipeline receipt points or primary gate stations to various points on the distribution grid. On North Shore Gas' system, these transmission and backbone distribution related mains range in size from 18 up to 30 inches in diameter. Based on a review of the gas distribution system design and operations with North Shore Gas' Engineering personnel, only the smaller sized mains, in the 2 to 16 inch range, were considered for the purpose of attaching customers. This comprises approximately 87% of North Shore Gas' pipeline system.

Q. Have you analyzed the relationship between the number of customers served by North Shore Gas and level of investment in distribution mains?

A. Yes. I have performed such an analysis and provided a graphical representation of the relationship between total installed footage of distribution mains that reflects the pipe sizes to which residential customer connections are typically made and the number of residential heating customers, the class of customers that represents most of the growth in recent years. This graph is shown on North Shore Ex. RJA–1.6. As would be expected, as the number of customers served by North Shore Gas increases, the level of investment in distribution mains, as measured by installed footage, also increases.

Q. Why would one expect there to be a strong correlation between the number of customers served by North Shore Gas and the length of its system of distribution mains?

A. Development of North Shore Gas' distribution grid over time is a dynamic process. Customers are added to the distribution system on a continuous basis under a variety of installation conditions. Accordingly, this process cannot be viewed as a static situation where a particular customer being added to the system at any one point in time can serve as a representative example for all customers. Rather, it is more appropriate to understand that for every situation where a customer can be added with little or no additional footage of mains installed, there are contrasting situations where a customer can be added only by extending the distribution mains to the customer's more remote or "off-system" location.

Q. Please continue.

A. Recognizing that the goal is to more reasonably classify and allocate the total cost of North Shore Gas' distribution mains facilities, it is appropriate to analyze the cost causative factors that relate to these facilities based on the total number of customers serviced from such facilities. Accordingly, the concept of using a minimum system or

"zero capacity" approach for classifying distribution mains simply reflects the fact that the average customer serviced by the utility requires a minimum amount of mains investment to receive such service. It is entirely appropriate to conclude that the number of customers served by North Shore Gas represents a primary causal factor in determining the amount of distribution mains cost that should be assessed to any particular group of customers. Thus, one can readily conclude that a customer component of distribution mains is a distinct and separate cost category that has much support from an engineering and operating standpoint.

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

A. Regarding North Shore Gas' major plant accounts, customer weighting factors were developed to allocate the following plant accounts: Services – Account No. 380, Meters – Account 381, Meter Installations – Account No. 382 and House Regulators – Account No. 383. These weighting factors reflect any differences in the current unit costs that particular customer groups cause the Company to incur. For example, the cost of a 3/4-inch plastic service line that could serve a residential customer costs less, on a per unit basis, than the cost of a 4-inch steel service line to serve a larger industrial customer. The use of weighting factors takes these unit cost differences into account when assigning costs to the various customer classes.

Q. How were you able to determine the particular type and size of facilities for each plant account attributable to each of the customer groups?

A. Based on its historical installation and operating experience, North Shore Gas has established engineering and operational standards which enable the direct identification

of the typical size, length and material type of service line by customer group. This information was obtained from the utility's customer information system and property records. Similarly, with regard to meters, North Shore Gas was able to conduct a detailed analysis of data, also contained in its customer information system and property records, that identified the type and size of meter for each customer it serves and this data can be aggregated by customer class. This approach was used to determine the type and size of equipment, by customer class, for house regulators and to assign the installation costs of meters and house regulators to specific customer classes.

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

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

Q. How did the ECOSS allocate distribution-related operation and maintenance expenses?

A. In general, these expenses were allocated on the basis of the cost allocation methods used for the Company's corresponding plant accounts. A utility's distribution-related operation and maintenance expenses generally are thought to support the utility's corresponding plant in service accounts. Put differently, the existence of particular plant facilities necessitates the incurrence of cost, *i.e.*, expenses by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account. For example, Account No. 893, Meters and House Regulator Expenses, is allocated on the same basis as its corresponding plant accounts, Account No. 381 – Meters and Account No. 383 – House Regulators. With the utility's detailed analyses supporting its assignment of plant in service components, where feasible, it was deemed

appropriate to rely upon those results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

Q. How did the ECOSS allocate Customer Accounting Expenses (FERC Account No. 902 – No. 904)?

A. Meter Reading Expense, Account No. 902, was allocated on the basis of the number of customers by class. A special study of the cost types and activities performed related to charges to Account No. 903, Customer Records and Collections Expense, resulted in the construction of a composite allocation derived from a weighting of the number of customers, bills and service charge revenues by class. An analysis of uncollectible expenses by class was conducted for the purpose of allocating Account No. 904, Uncollectible Accounts Expense. The analysis revealed that the residential (Rate 1) and general service (Rate 2) classes are the source of uncollectible costs on the North Shore Gas system. Therefore, the allocation of Account No. 904 expenses was limited to these two classes.

Q. How did the ECOSS allocate Administrative and General expenses and was it reasonable?

A. Administrative and General ("A&G") expenses were allocated in accordance with the Commission's findings in North Shore Gas' last rate case. Specifically, A&G expense Account No. 924, Property Insurance, was allocated on the basis of total plant; Accounts 925, Injuries and Damages and 926, Pensions and Benefits, were allocated on the basis of North Shore Gas' labor expenses; and all other A&G accounts were allocated on the basis of total O&M, exclusive of A&G. This is a reasonable approach to allocating A&G expenses.

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

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

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

A. Deferred income taxes, investment tax credits and other tax adjustments were allocated on a total plant basis. Current income taxes were allocated based on each individual class' net operating income.

VII. <u>RESULTS OF NORTH SHORE GAS' ECOSS</u>

Q. Please discuss the results of the ECOSS filed by North Shore Gas.

A. Referring to North Shore Ex. RJA – 1.1, the following results at present rates from the Company's Coincident Peak study are indicated on Line No. 18:

1. The average system rate of return is 7.12%.
2. The residential non-heating service class (Rate 1N) exhibits the lowest rate of return at a **negative** 1.68%.
3. The residential heating service class (Rate 1H) shows a rate of return of 5.89%, below the system average return of 7.12%.

4. The general service class (Rate 2) currently provides the second highest rate of return of any class at 10.06%.

5. The large volume commercial and industrial class (Rate 3) is also providing a return well above the system average at 19.44% (the highest return among all classes).

6. The standby service class' (Rate 5) rate of return is also below the system average at 5.75%.

Q. Why have you not addressed Rates 4 and 6?

A. Service classes 4 (Contract Service for Electric Generation) and 6 (Contract Service) do not appear in the exhibit, as they have been excluded from the ECOSS. No customers are presently receiving service under Rate 4 and the customer-specific charges under Rate 6 are negotiated pursuant to special anti-bypass contracts. Revenues received from this service class were treated as a credit to the remaining service classes in the ECOSS.

Q. Is there anything noteworthy about the ECOSS results?

A. Yes. The ECOSS results exclude from North Shore Gas' proposed base rate revenue requirement the gas cost portion of the utility's uncollectible expense. This has been done to reflect the impact of North Shore Gas' proposed Rider UBA, Uncollectible Balancing Adjustment. For illustrative purposes, however, a separate set of cost of service summary schedules has been provided which includes the previously mentioned uncollectible expenses in North Shore Ex. RJA – 1.7. Rider UBA is described in more detail by North Shore Gas witness Mr. Feingold (North Shore Ex. RAF-1.0) and is also addressed by Ms. Grace.

Q. Please explain how the Unit Cost Analysis presented in North Shore Ex. RJA – 1.2 was prepared.

A. First, the functionalized, classified and allocated costs and rate base data for each class of service were extracted and the system average rate of return to the allocated rate base was applied to determine the required net income. Next, this amount was grossed up to account for the income and general tax related revenue responsibilities. The sum of the expense related revenue requirement and the rate base related revenue requirement yields the total revenue requirement for each component of cost at the system average rate of return. The computer model that was utilized made this calculation for each of the various cost components, *i.e.*, the customer, demand and commodity portions of the production, storage, transmission, distribution, and customer accounts and sales functional categories. The summary total of these calculations is shown in North Shore Ex. RJA - 1.2. It should be noted that a monthly customer cost is calculated for each customer class, as well as unit commodity and demand costs.

Q. Please compare the ECOSS results using the Company's preferred coincident peak demand method with results utilizing the coincident peak demand method, with a portion of distribution mains classified as customer related and the average and peak methodologies.

A. A comparative table of the class-by-class rates of return at present rates under North Shore Gas' coincident peak method, with a portion of distribution mains classified as customer related and the alternative cost of service methods are shown in North Shore Ex. RJA – 1.8. Summary schedules containing the cost study results under the alternative cost allocation methods are presented in North Shore Exs. RJA – 1.9 and RJA – 1.10.

Q. Please summarize the reasons why the coincident peak methodology was chosen by North Shore Gas as its proposed allocation methodology.

A. The utility's proposed allocation methodology was chosen for the following reasons:

1. As a capacity allocation approach, the coincident peak method best reflects cost causation on the utility's system,
2. It reflects the principles deemed appropriate by the Commission in establishing a demand allocation methodology, that is, it is related to the actual system as built to serve all classes of customers,
3. It has a sound conceptual and theoretical basis, and
4. It strikes a balance between the other commonly used, primary cost allocation methodologies that either support other cost causative principles or give recognition to system utilization characteristics.

Q. Does this complete your direct testimony?

A. Yes.