NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

RONALD J. AMEN

AND

JOHN D. TAYLOR

ATRIUM ECONOMICS, LLC

New Hampshire Public Utilities Commission

Docket No. DG 21-104

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SCHEDULES

I. INTRODUCTION

Q. Please state your names and business address.

A. Our names are Ronald J. Amen and John D. Taylor. Our business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina 29926.

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

A. We are appearing on behalf of Northern Utilities, Inc. ("Northern" or the "Company"). Northern has retained Atrium to conduct the weather normalization and annualization of its billing determinants; the allocated class cost of service study ("ACOSS"); the marginal class cost of service study ("MCOSS"); the revenue apportionment and revenue targets by class; and the rate design for existing rate classes.

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

A. We are employed by Atrium Economics, LLC ("Atrium") as Managing Partners.

Q. Have you prepared an Appendix describing your professional qualifications?

A. Yes. Appendix A to our direct testimony presents our professional qualifications.

Q. Please describe Atrium's business activities.

A. Atrium offers a complete array of rate case support services including advisory and expert witness services relating to revenue recovery, pricing, integration of technology, distributed generation, and affiliate transactions. We have extensive experience in rate case management; revenue requirement development; allocated embedded and marginal cost of service studies; rate design and rate alignment; and affiliate and shared services.

We have appeared as expert witnesses on behalf of energy utilities in regulatory proceedings across North America supporting financial, economic, and technical studies before numerous state and provincial regulatory bodies, as well as before the Federal Energy Regulatory Commission (FERC). The Atrium Team has extensive background and experience both in management positions inside electric and gas utilities and as advisors to our clients.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. We have provided pre-filed direct testimony in Unitil Energy Systems Inc. 2021 general rate case, Docket No. DE 21-030.

Q. Please summarize the topics addressed in your testimony.

A. Atrium analyzed Northern's respective historical actual and normal weather data sourced from the National Oceanographic and Atmospheric Administration ("NOAA") to determine the basis for the establishment of normalized sales and transportation throughput for purposes of determining the Company's weather-normalized pro forma billing determinants and revenues in its general rate case.

Our testimony discusses the role of the ACOSS and MCOSS in providing guidance toward designing economically efficient rates. Cost causation is a fundamental principle for these studies. Understanding cost causation requires an indepth understanding of the planning and operation of the utility system, as well as the basic economics of the gas system components.

The ACOSS and MCOSS prepared for this case reveal how Northern incurs costs to serve its various classes of customers. The single most important conclusion from the cost studies is that in order to collect the costs from customers who cause the costs to be incurred, rates must better reflect the nature of these costs.

Finally, Atrium will sponsor the Company's proposed revenue requirement apportionment and rate design proposals, and the resulting bill impacts by rate class.

II. WEATHER NORMALIZATION

Q. Please define weather normalization within the context of Northern's rate case filing.

A. Weather normalization is the process of determining a representative level of gas sales and transportation throughput for the Company's 2020 test year under a predefined level of normal weather conditions, which is represented by an historical average level of Effective Degree Days ("EDD"). EDD reflect an adjustment to standard heating degree days for the effect of wind speed on temperature. Northern has consistently relied on EDD for its weather analysis based on its demonstrated high correlation with the Company's gas throughput.

Q. What is the Company's basis for determining normal weather for its New Hampshire gas distribution system?

A. Northern defines normal weather as the average annual EDD over the most recent 20-year period. Based on a 2020 energy industry survey,[1] 20-year normal weather is the most commonly used normal weather period in the energy industry. The Company provided Atrium with daily actual and normal EDD data for the 20-year period ending December 2020.

Q. Please describe the weather normalization method employed by Atrium.

A. Atrium used actual "per books" billing month consumption volumes by customer class to determine actual average use per customer per day. Regression analysis was then performed for this usage data against actual EDD for the most recent five-year period, or 60 months, for each customer class. Resulting base load per customer and heating coefficients per EDD by class were then applied to actual monthly customers and normal EDD, respectively. Our normalization calculations employed an adjusted base load factor statistic from the regression analysis for each winter month to account for the effect of winter weather on base load usage. The monthly weather adjustment resulted from the difference between the normal and actual 2020 monthly therms. In some months, actual weather was warmer than normal while in other months the weather was colder. In total, the weather for test year 2020 was warmer than normal, resulting in a positive net weather adjustment to throughput of approximately five million therms, as shown in column L of Schedule RAJT-2, labeled "WN Therm Adjustment." Two customer classes, G50/T50 (Low Annual,

[1] *Forecast Accuracy Benchmarking Survey and Energy Trends*, Itron, 2020, copyright protected (Proprietary and Confidential).

Low Winter) and G52/T52 (High Annual, Low Winter) were not weather normalized, as the regression results for these classes did not indicate statistically significant heat sensitivity.

Q. Please describe the net revenue adjustment for each customer class resulting from Atrium's weather normalization process.

A. The weather adjustment therms in column L of Schedule RAJT-2 were multiplied by the volumetric block rate components in each rate schedule to derive the weather normalized revenue impact for each class, as shown in column M of Schedule RAJT-2, labeled "WM Revenue Adjustment."

III. PRO FORMA BILLING DETERMINANTS

Q. Please describe the development of the proforma billing determinants and revenues at current rates.

A. A Customer Annualization Adjustment, as shown in Schedule RAJT-2, was performed using the test year-end number of customers by class to determine the Year-End Customer Adjustment (column P) and Annualization Therm Adjustment (column Q) by class. The respective numerical adjustments were priced at the corresponding current customer charges and volumetric block rates to determine the Annualization Revenue Adjustment by class (column T).

Q. Has there been any further adjustments to class billing determinants or proforma revenues?

A. Yes. An annualization adjustment was made for Rate R-10, Residential Heating, Low

Income, to reflect a change in the customer charge for the months of November and December of the test year. This adjustment is shown in column U of Schedule RAJT-2. The Pro Forma Total Therm Adjustments and corresponding Revenue Adjustments by class are shown in columns V and W respectively, of Schedule RAJT-2.

Q. Have the pro forma billing determinants been reflected the Northern's Revenue Proof?

A. Yes. The preceding weather normalization and annualization adjustments are the basis for the pro forma 2020 Adjusted Billing Determinants and 2020 Adjusted Base Year Revenue at Current Rates in the Revenue Proof and Rate Design, Schedule RAJT-11.

Q. Has Atrium provided calendar month consumption information by customer class?

A. Yes. Atrium developed calendarized revenues per customer by class from the monthly billing cycle revenue per customer. Ratios of billing cycle consumption occurring in the same calendar month were used to allocate monthly billing cycle revenues by class to the corresponding calendar month basis. Monthly calendarized revenues per customer by class will be used in Northern's proposed decoupling mechanism, sponsored by witness Mr. Timothy S. Lyons. Schedule RAJT-12 provides a summary of the calendar month revenue per customer analysis by class.

IV. PURPOSE AND PRINCIPLES OF COST ALLOCATION

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

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

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

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

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (an historical period) or the estimated book value of costs for a forecast test year or some combination of historical and future costs. Where a forecast test year is used, the costs and revenues are typically derived from budgets prepared as part of the utility's financial plan. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

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

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

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

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

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

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

However, the existence of common costs makes any allocation of costs problematic from a strict economic perspective. This is theoretically true for any of the various utility costing methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy-free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy-free so long as the price exceeds the incremental cost of providing service but is less than stand-alone costs ("SAC"). The logic for this concept is that if customers' prices exceed incremental cost, those customers contribute to the fixed costs of the utility. All other customers benefit from this contribution to fixed costs because it reduces the cost they are required to bear. Prices must be below the SAC because the customer would not be willing to participate in the service offering if prices exceed SAC.

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

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of *cost causation*. Cost causation, as alluded to earlier, addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs. To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers.

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

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

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

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

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

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

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

A. To establish these relationships, the Company must analyze its gas system design and operations, its accounting records as well as 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.

In order to accomplish this, Atrium reviewed Northern's expense and plant accounts, operational data, usage information, and conducted interviews with Northern employees. The details and data gathered provided information on the key factors that cause the costs to vary and supported studies of the relative costs of providing facilities and services for each rate class. 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 what you mean by the term "direct assignment."

A. 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 an ACOSS, the analyst seeks to maximize the amount of plant and expense directly assigned to a particular customer group 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 specific 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?

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

Q. Please describe the process of performing an ACOSS analysis?

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: (1) functionalization; (2) classification; and (3) allocation.

The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. Northern's primary functional cost categories associated with gas service include production, distribution, onsite, and customer accounts and services. Indirect costs that support these functions, such as intangible plant, general plant, and administrative and general expenses, are allocated to functions using allocation factors related to plant and/or labor ratios, i.e., internal allocation factors.

Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics previously discussed: (1) customer, (2) demand or capacity, and (3) commodity. The final step is the allocation of each functionalized and classified cost element to the individual customer class. Costs typically are allocated on customer, demand, commodity, or revenue allocation factors.

From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred by a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by rate class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the way customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics and have different costs based on size and type.

Therefore, differences in the cost of meters are reflected by using a different average meter cost for each class of service.

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

A. Yes. The factors which can influence the cost allocation used to perform a COSS 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 Northern's ACOSS?

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 the utility operates in 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 distribution system are important, such as whether the distribution system is a centralized or a dispersed one. 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. How does the availability of data influence an ACOSS?

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.

Q. How do state regulatory policies affect a utility's ACOSS?

A. State regulatory policies and requirements prescribe whether there are any historical precedents used to establish utility rates in the state. Specifically, state regulations and past precedents set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the proposed cost allocation method utilized by the utility.

V. NORTHERN'S ALLOCATED COST OF SERVICE STUDY

Q. What was the source of the cost data analyzed in the Company's ACOSS?

A. All cost of service data was extracted from the Company's total cost of service (i.e., total revenue requirement) and schedules contained in this filing. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by Company personnel.

Q. How are the Northern rate classes structured for purposes of conducting its ACOSS?

A. For Northern's ACOSS, eight rate classes were included:

- Residential Heating Service (Rate R-5) and Residential Low Income (R-10)
- Residential Non Heating Service (R-6)
- Commercial & Industrial Service (Low Annual, High Winter) (G-40, T-40)
- Commercial & Industrial Service (Low Annual, Low Winter) (G-50, T-50)
- Commercial & Industrial Service (Medium Annual, High Winter) (G-41, T-41)
- Commercial & Industrial Service (Medium Annual, Low Winter) (G-51, T-51)
- Commercial & Industrial Service (High Annual, High Winter) (G-42, T-42)
- Commercial & Industrial Service (High Annual, Low Winter) (G-52, T-52)

Q. What are the similarities and differences in the cost allocation approach utilized in Northern's ACOSS in this proceeding with that utilized in Northern's previous rate case?

A. With the exception of the classification and allocation of Distribution Mains, the general methods employed in Northern's previous general rate case proceeding, Docket No. DG 17-070 ("2017 Case"), are reflected in the ACOSS methods employed in the current proceeding and described in my testimony. Updated data was utilized to develop the special studies and analyses that inform the calculations and outcome of the ACOSS, but the general approaches used in the current proceeding are in alignment with the 2017 Case. The primary studies are summarized below:

<u>Indirect Production & Overheads Study</u> – The Atrium ACOSS is fully

unbundled; therefore, the costs in this category are captured in the Function of the same name. The prior case had separate cost of service studies for Production only and Delivery only.

<u>LNG Storage</u> – LNG Storage plant and O&M costs are included in the Indirect Production & Overheads function and allocated based on the design day for each class. In the 2017 Case LNG Storage costs were included in the Production only cost of service study and allocated on the ratio of remaining design day demands.

<u>Classification of Distribution Mains</u> – Mains are classified between a customer component and a demand component, as described in more detail below. In the prior rate case, Mains were classified as 100% demand related.

<u>Special Studies</u> – Atrium's ACOSS included special studies for meters, services, other revenue, uncollectible costs, meter reading, and customer deposits. Studies from the prior rate case included meters, services, uncollectible costs, and customer deposits.

Q. How did the Company's ACOSS classify and allocate investment in Distribution Mains?

A. The Company ACOSS classified 34% of the investment in distribution mains as customer related and 66% of the investment as demand related. The customer related portion of the distribution mains investment was then allocated based on the number of customers on Northern's system. The demand related investment was allocated to the customer classes based on their respective contribution to peak day demand under system design weather conditions, in other words, on a "design day" basis.

Q. **Please explain the basis for the choice of classification and allocation methods?**

A. It is widely accepted that distribution mains are installed to meet both system peak period load requirements and to connect customers to the utility's gas system. Therefore, to ensure that the rate classes that cause the Company 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 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 gas distribution 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 this method used to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?**

A. Yes. The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach and 2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept approach, which is the method relied upon in the Company's cost study, 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 Company's gas system against the 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 Company's distribution system, regardless of the customer's peak or annual gas consumption; that is, the installation is unrelated to either peak gas flows or average gas flows. Rather, these distinct 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.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. That is, the 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. For purposes of determining the customer component of distribution mains to be used in Northern's ACOSS, the minimum system method was employed to test the reasonableness, by comparison, of the results of the zero-intercept method.

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, Electric Utility Cost Allocation Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("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.

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. With respect to Northern's specific operating experience, is there demonstrable evidence to support the use of a customer component of distribution mains?

A. Yes. In developing an appropriate cost allocation basis for distribution mains, the two methods of cost analysis mentioned in the previous response were conducted for the Company's investment in distribution mains, by size and material type of main installed. Applying the regression results of the "zero inch" distribution main, which was $25.21 per foot for plastic mains, to the Company's total footage of distribution mains results in an investment amount equivalent to approximately 34% of the total investment in distribution mains, on a current cost (year 2020) basis. For the purpose of comparison, the most commonly installed, minimum-sized distribution mains analysis focused on 2-inch diameter plastic pipe. The dominant pipe size for new distribution main installations by far is 2-inch plastic, with over 1.2 million feet installed. The 2-inch plastic pipe analysis, adjusted downward to account for its load carrying capacity, yielded a minimum system result of 41.5%. These results are provided in Schedule RAJT-9 - Customer Component of Mains Analysis. Both methods are supportive of the 34% classification of distribution mains as customer related used in the ACOSS model.

Q. Would one expect there to be a strong correlation between the number of customers served by Northern and the length of its system of distribution mains?

A. Yes. Development of the Company's 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 and appreciate 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 "off-system" location.

Recognizing that the goal is to more reasonably classify and allocate the total cost of Northern's distribution mains facilities, it is appropriate to analyze the cost causation 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 approach for classifying distribution mains simply reflects the fact that the average customer serviced by the Company requires a minimum amount of mains investment to receive such service. Thus, it is entirely appropriate to conclude that the number of customers served by Northern represents a primary causal factor in determining the amount of distribution mains cost that should be assessed to any particular group of customers. 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. How did the ACOSS allocate distribution-related gas operation and maintenance ("O&M") expenses?

A. In general, these expenses are allocated based on the cost allocation methods used for the Company's corresponding plant accounts. A utility's O&M expenses generally are thought to support the utility's corresponding plant in service accounts. Put differently, the existence of 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. 887, Maintenance of Mains, is allocated on the same basis as its corresponding plant accounts, Mains – Account No. 376. With the detailed analyses supporting the assignment or allocation of major 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. Please describe the classification and allocation of Customer Accounts and Customer Service expenses in the COSS.

A. Customer accounts and services expenses were classified as customer-related costs and allocated based on the average number of distribution customers by class. Exceptions to this treatment were Account Nos. 902 (Meter Reading) and 904 (Uncollectible Accounts). The allocation factor for meter reading expenses included additional time and effort related to meter reading for manual meter reading activities. Uncollectible accounts expenses are assigned to the classes based on an analysis of bad debt expenses.

Q. How were administrative and general ("A&G") expenses and taxes allocated to each rate class?

A. A&G expenses were allocated on an account-by-account basis. Items related to labor costs, such as employee pensions and benefits, were allocated based on O&M labor costs. Items related to plant, such as maintenance of general plant and property taxes, were allocated based on plant. Regulatory Commission expense was allocated on rate base.

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 COSS 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 each tax expense category. Generally, taxes can be cost classified on the basis of the tax assessment method established for each tax category and can be grouped into the following categories: (1) labor; (2) plant; and (3) rate base. In the Northern COSS, 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 rate class?

A. Current income taxes were allocated based on each class' net income before taxes. Income taxes for the total revenue requirement were allocated to each class based on the allocation of rate base to each class. Income taxes at proposed revenues by class were allocated to each class based on the income prior to taxes for each class.

Q. Does Northern's COSS include gas commodity costs?

A. No. However, there are indirect production and overhead costs within the COSS which are recovered through the Company's Cost of Gas Adjustment mechanism. The details relating to these costs and the associated revenue requirement of $826,413 are presented in Schedule RAJT-3, Summary of Cost Functionalization.

VI. SUMMARY OF THE ALLOCATED COST OF SERVICE STUDY

Q. Please summarize the results of Northern's COSS.

A. The following **Table 1** provides a high-level summary of the results of the ACOSS. It shows the rate of return for each rate class based on current rates as well as the system overall return, the revenue deficiency or excess for each rate class at the uniform system rate of return, and the revenue-to-cost ratio for each class.

Table 1

Summary Results of the Company's ACOSS

Rate Class	Class Revenue (Deficiency)/ Excess	Rate of Return on Net Rate Base	Revenue to Cost Ratio
Residential HeatR-5, R-10	(5,235,399)	3.58%	0.82
Residential Non-HeatR-6, R-11	(484,346)	-5.61%	0.54
High Winter SmallG-40, T-40	(1,486,126)	4.48%	0.84
Low Winter Small G-50, T-50	49,432	10.37%	1.05
High Winter MediumG-41, T-41	(1,180,973)	4.81%	0.83
Low Winter MediumG-51, T-51	106,343	11.29%	1.09
High Winter LargeG-42, T-42	(480,404)	3.91%	0.78
Low Winter LargeG-52, T-52	697,045	16.74%	1.35
Total Company	(8,014,427)	4.74%	0.85

Regarding rate class revenue levels, the resulting revenue-to-cost ratios show that all but three classes, Low Winter Small (G-50, T-50), Low Winter Medium (G-51, T-51, and Low Winter Large (G-52, G-T-52) are being charged rates that recover less than their indicated costs of service.

Q. Do these results provide guidance for the allocation of revenue requirements in this case?

A. Yes. Cost of service is a useful tool for determining the allocation of the revenue deficiency to each rate class. Cost of service is not, however, the only consideration in determining the portion of the revenue deficiency allocated to each rate class. Other considerations include principles such as gradualism, competitive considerations, standalone costs and avoiding or minimizing the potential for compromising the integrity of current rate classes.

Q. Has Northern taken the above factors into account in recommending the level of rate increase for rate classes?

A. Yes. The process for determining the revenue increase for each class is addressed in **<u>Section V</u>** of this testimony.

Q. Please describe the ACOSS schedules attached to this testimony.

A. Five schedules provide further details of the ACOSS that include the following information:

- Schedule RAJT-4 consists of two pages and presents the results of the class cost of service study for the test year. Class rate of return and net income may be found on page 1, and the revenue requirement for each class at the uniform rate of return by rate schedule is shown on page 2 of this schedule.
- Schedule RAJT-5 provides a single page illustration of the process followed to develop the Company's proposed class revenue allocation.

- Schedule RAJT-6 consists of 3 pages and presents the ACOSS unit cost report.
- Schedule RAJ-7 consists of 2 pages and provides the summary of the ACOSS external allocation factors.
- Schedule RAJT-8 consists of 5 pages and provides a description of the functionalization and classification of the USOA accounts.

VII. MARGINAL COST OF SERVICE STUDY

Q. Please describe the purpose for the preparation of a marginal cost of service study?

A. Marginal cost of service studies do not typically reflect actual costs but rely on estimates of the expected changes in costs associated with changes in service levels; and are therefore, forward-looking to the extent permitted by the available cost data. Marginal cost studies are most useful for rate design where it is important to send appropriate price signals associated with additional consumption by customers. Marginal cost studies can inform rate design particularly as it relates to customer and demand related costs for a utility that provides default supply services to retail customers who do not elect an alternate gas commodity supplier.

Q. Please describe the Company's MCOSS.

A. Marginal cost studies focus on the change in costs associated with a small change in the number of customers or load added to the utility's system, or the cost to replace the current customer related infrastructure to continue service to an existing customer. As stated earlier, marginal costs are generally forward-looking and require making estimates of future costs with an understanding of the elements that drive those future costs. As a practical matter, marginal costs bear no relationship to the mix of actual historical costs that constitute the utility revenue requirement. The reasons that marginal costs do not reflect actual costs used in a utility's revenue requirement calculations include the following:

- The relationship between historic and prospective costs reflects changes in technology.
- Sunk costs (the fixed cost of the existing system) do not impact marginal cost but may account for a large portion of the test year revenue requirement particularly where economies of scale are significant.
- The underlying impacts of inflation on prospective costs cause such costs to differ from past costs.
- Additions to the utility system are lumpy, and as a result, utilities' optimal additions often include more capacity than the marginal change in customer count or customer demand.

An example of the latter point is addressed in Northern's system improvement planning process:

"Unlike mains extensions that are installed to serve known load, system improvements are completed in advance to ensure the system has the capacity required to meet planning criteria. The capacity increase associated with system improvement projects tend to be a lumpy investment, meaning that the amount of capacity is determined based upon standard equipment and materials and is not able to be fine-tuned to the amount of load forecasted."[2]

Q. Please discuss the steps followed to prepare a MCOSS for a gas utility such as Northern.

A. To estimate marginal cost, the first step requires determining the change in cost associated with the incremental consumption of natural gas. The increment may be defined as the number of customers, the design day demand, or the additional commodity. In this case, there is no reason to estimate the incremental commodity cost because gas costs are a pass-through cost element. Essentially, marginal cost requires an understanding of the utility's system planning process. Often however, the planning process does not provide all of the information necessary to develop complete marginal cost estimates.

The second step in the determination of marginal cost relates to the change in capacity requirements as measured by the utility's design day demand. Unlike the commodity determination, there is no competitive market for the utility's distribution function. Thus, it is necessary to estimate how customers' demand for design day capacity influences the costs for distribution. Gas distribution systems are typically built using engineering design standards that take into consideration customer density and the expected design day demands of those customers. For customers who use the utility's gas delivery system for heating as opposed to process usage or interruptible

[2] Direct Testimony of Kevin E. Sprague and Christopher J. LeBlanc, at 12:9-14.

services, their demands tend to be coincident. Distribution facilities for larger commercial and industrial customers are generally designed on a case-by-case basis, given the expected peak load of the customer. In short, the local distribution system is designed based on the design load of the customers to be served.

The concept of a network cost provides a convenient way to discuss the marginal distribution costs. Network costs represent the cost of the interconnected facilities that serve distribution system demand and include mains, service lines and meters. The customer component of these facilities is related to the smallest size of the equipment that is installed to serve customers. If larger equipment is installed, the extra costs are demand related. The economies of scale in the distribution system means that the demand related cost is often less significant than the customer component. It also means that per unit cost of serving larger customers is lower than the cost to serve smaller customers.

Q. How have you identified the minimum size components used by Northern's distribution system?

A. Yes. The distribution engineering and operations personnel at Northern were interviewed to gain an understanding of the smallest standard size of facilities used. In addition, the Company's accounting function personnel were consulted to determine the fully loaded installed costs of these components. The customer component of distribution mains, which informs the minimum system, is discussed in **Section V**, Northern's Allocated Cost of Service Study. Meters and services are considered entirely customer related. The MCOSS schedule also provides the economic carrying charge rate for each plant component. The schedule produces the marginal revenue requirement for Northern associated with customer and demand related capital expenditures. The economic carrying charge rate uses Northern's marginal capital costs based on the current filing. The forward-looking nature of a marginal cost study requires that the capital cost be estimated on an incremental basis not on embedded costs.

Q. Did you identify the general plant related to the minimum system?

A. Yes, the customer and demand related general plant was identified based on average embedded costs as a proxy for long-run marginal costs.

Q. Why are average embedded costs a reasonable proxy for marginal costs?

A. General plant costs do not vary directly with either demand or customers. That is the reason that in the allocated cost of service they are allocated on composite allocation factors. For example, customer growth only impacts the number of employees and therefore payroll expense when large discreet blocks of customers are added. If we used a pure marginal cost allocation factor, the payroll component growth related to customers or demand would be zero for a number of years and would be the full cost of a new employee only when the threshold number of customers requiring additional employees reached the tipping point in the level of services provided. By using an average cost value, the marginal cost study recognizes the contribution of each new customer to the future requirement of a new employee or new office space.

Q. Have you identified the customer related expenses?

A. Yes. The customer related expenses may be found in Schedule RJA-10, which presents the Company's full marginal cost study. These expenses were based on embedded costs as a proxy for long-run marginal costs. In the short run, these costs would be zero because adding one customer does not change most of these costs. However, at some level these costs would increase by an amount related to the average cost when a minimum number of customers have been added. This approach provides a reasonable proxy for the O&M related costs.

Q. Did you identify the A&G costs related to the minimum system?

A. Yes, customer and demand related A&G costs were identified based on embedded costs as a proxy for long-run marginal costs.

Q. Please summarize the results of the company's customer and demand costs on an embedded and a marginal cost basis.

A. The results are summarized in **Table 2** below.

Table 2

Summary of Unit Costs by Class

Rate Class	Unit Customer Costs ($/Month)		Unit Demand Cost ($/DDDth-Month)	
	(B)	(C)	(D)	(E)
	Embedded	Marginal	Embedded	Marginal
Residential HeatR-5, R-10	71.71	56.20	21.04	24.69
Residential Non-HeatR-6, R-11	72.33	56.05	21.04	24.69
High Winter SmallG-40, T-40	86.60	71.71	21.04	24.69
Low Winter Small G-50, T-50	86.76	71.91	21.04	24.69
High Winter MediumG-41, T-41	187.51	159.07	21.04	24.69
Low Winter MediumG-51, T-51	187.21	160.87	21.04	24.69
High Winter LargeG-42, T-42	725.70	720.13	21.04	24.69
Low Winter LargeG-52, T-52	736.61	729.25	21.04	24.69
Total System	78.70	62.94	21.04	24.69

As the table illustrates, the Residential customer-related costs calculated in both cost studies are significantly greater than the current customer charge. Thus, a customer facilities-related charge increase is warranted and consistent with the indicated cost of service. Increasing the customer charge and reducing the volumetric charge is also consistent with both marginal cost pricing and achieving just and reasonable rates.

Q. Would the proposed allocation of the company's proposed revenue requirements differ based on using marginal costs instead of embedded costs?

A. Any differences would not be material. Considering the Company's proposed revenue allocation, the end result would have been the same. However, there is more long-term stability in embedded costs, and it is more reflective of the cost causation principle. Therefore, I believe the ACOSS is a more reasonable alternative.

VIII. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design utilized in development of the

Company's rate design proposals.

A. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles include:

(1) Cost of Service,

(2) Efficiency,

(3) Value of Service,

(4) Stability/Gradualism,

(5) Non-Discrimination,

(6) Administrative Simplicity, and

(7) Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[3]

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of

[3] Principles of Public Utility Rates, Second Edition, Page 111-113 James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988.

existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the gas utility system is designed and constructed to meet the design day requirements of customers using the most economic equipment and technology consistent with design standards.

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

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

Q. Please discuss the principle of stability.

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

Q. Please discuss the concept of non-discrimination.

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

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that "equals should be treated equally" and vertical equity requires that "unequals should be treated unequally." Specifically, these principles of equity require that where cost of service is equal – rates should be equal and, where costs are different – rates should be different.

Q. Please discuss the principle of administrative simplicity.

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

Q. Please discuss the principle of the balanced budget.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that was previously discussed from the perspective of customer rates.

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

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. As noted above, there are tensions between cost and value of service principles. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. How are these principles translated into the design of rates?

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

IX. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Northern's proposed revenue increase of $7.8 million to its customer classes.

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

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

A. Yes. Using Northern's proposed revenue increase, and the results of its COSS, Atrium evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with Northern personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The benchmark option evaluated under Northern's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00 (Unity), as shown in Schedule RAJT-5, Proposed Revenue Allocation by Class, under *Scenario A - Revenues at Equalized Rates of Return*. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This decision was also made in consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

A second option considered was assigning the increase in revenues to Northern's customer classes based on an equal percentage basis of its current non-gas revenues (see *Scenario B - Equal Percentage Increase*, in Schedule RAJT-5). By definition, this option resulted in each customer class receiving an increase in revenues. However, when this option was evaluated against the COSS Study results (as measured by changes in the revenue-to-cost ratio for each customer class); there was no movement towards cost for most of Northern's customer classes (*i.e.*, there was no convergence of the resulting revenue-to-cost ratios towards unity or 1.00). In fact, the disparity in cost responsibility between the classes was widened. While this option was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provides further guidance to develop Northern's class revenue proposal.

Q. What was the result of this process?

A. After further discussions with Northern, Atrium concluded that the appropriate interclass revenue proposal would consist of adjustments, in varying proportions, to the present revenue levels in all of Northern's customer classes while the minimum class increase is set to fifty percent of the system average, as shown in <u>Schedule RJA-5</u> as *Proposed Class Revenues*. In the case of the Residential Heat class (R-5/R-10), the revenue adjustment at 1.25 times the system average ensures their proposed rates will move class revenues closer to the allocated cost of service for the class at 0.95 revenue-to-cost ratio. The proposed revenue increase to the Residential Non-Heat (R-6/R-11) class of twice the system average increase will improve the class' revenue-to-cost ratio from 0.45 to 0.63, below unity (1.00) at the Company's proposed ROR of 7.75%. Proposed increases for the G-40/T-40, G-41/T-41, and G-42/T42 classes were 75% of the system average increase, which brings their revenue-to-cost ratios 0.96, 1.08 and 1.05, respectively. The ACOSS results for the remaining customer classes (G-50/T50, G-51/T-51, G-52/T-52) indicate their respective class rates of return are at or above the system average rate of return at both the Company's current and proposed ROR levels. While this would suggest the need for revenue decreases in order to move many of these customer classes closer to cost (*i.e.*, convergence of the resulting revenue-to-cost ratios towards unity or 1.00), as shown in <u>Schedule RJA-5</u> under *Revenues at Equalized Rates of Return*, the resulting customer impact implications for the Residential Service classes has led us to conclude, in consultation with the Company, to refrain from revenue reductions for these classes or alternatively exempting these classes from revenue increases (*Scenario B*). Instead, the proposed respective revenue adjustments of 50% of the system average increase will mean these two classes will be higher than their current parity ratio levels relative to unity. The resulting allocation of the total revenue increase of $7,782,951 to the respective rate classes is presented in **Table 3**, below.

Table 3

Proposed Class Revenue Apportionment

Rate Class	Revenues at Current Rates	Revenues at Proposed Rates	Proposed Revenue Change	Percent Change	Revenue to Cost Ratio
Residential HeatR-5, R-10	20,731,783	25,996,394	5,264,611	25.39%	0.95
Residential Non-HeatR-6, R-11	493,626	692,442	198,816	40.28%	0.65
High Winter SmallG-40, T-40	6,745,829	7,764,703	1,018,874	15.10%	0.96
Low Winter Small G-50, T-50	1,024,226	1,127,357	103,131	10.07%	1.10
High Winter MediumG-41, T-41	5,235,691	6,026,477	790,786	15.10%	1.08
Low Winter MediumG-51, T-51	1,396,947	1,537,608	140,661	10.07%	1.27
High Winter LargeG-42, T-42	1,545,114	1,778,485	233,370	15.10%	1.04
Low Winter LargeG-52, T-52	2,623,624	2,887,802	264,177	10.07%	1.75
Special Contracts Revenue	1,197,813	1,197,813	0	0.00%	
Indirect Production & OH Revenue	1,057,890	826,413	-231,477	-21.88%	
Miscellaneous Revenue	1,147,705	1,147,705	0	0.00%	
Total Company	43,200,249	50,983,199	7,782,951	18.02%	1.00

Q. Please summarize the overall benefit provided by your proposed class revenue apportionment.

A. In summary, the preferred revenue allocation approach in Schedule RJA-5, *Scenario C* results in reasonable movement of the Residential and High Winter Small Commercial classes revenue-to-cost ratios toward unity or 1.00, while providing moderation of the revenue impact on this class by requiring varying levels of revenue increase responsibility from the other customer classes for the Company's total proposed revenue requirement. From a class cost of service standpoint, this type of class movement, and modest reduction in the existing class rate subsidies, is desirable.

X. NORTHERN'S RATE DESIGN

Q. Please summarize the proposed rate design changes.

A. In consultation with Northern, Atrium is proposing changes to monthly customer charges. We are recommending an increase to the Residential (R-5/R-10, R-6) customer charges equal to the percentage revenue increase (25.4%) to the Residential Heat class from $22.20 to $27.84 per month. Modest increases were made to the customer charges for the remaining non-residential rate schedules.

Atrium is also proposing to remove all seasonally differentiated volumetric rates in the rate schedules where the winter/summer rates remain with one exception; that is, Rate Schedule G-52/T-52. While there is no demonstrable cost of service support for the current seasonal differences in the rates, eliminating the winter/summer rate differential will cause disproportionate increases for G-52/T-52 customers with primarily summer season consumption.

Finally, all rate schedules with current multi-block volumetric rates have been reduced to a single flat block, which continues the transition of the volumetric rates from Northern's 2017 rate case. These proposed changes to the volumetric rates will simplify bill calculation and presentation of the information on customer bills, in addition to the monthly revenue per customer by class calculations used in the Company's proposed decoupling mechanism, and provide some winter bill reductions to heating load customers when monthly bills are the highest.

Q. Have you provided a schedule detailing the proposed rates and corresponding revenues?

A. Yes. Schedule RAJT-11, Revenue Proof and Rate Design, presents summaries by customer class of the proposed revenue increases. This schedule displays the revenues calculated under the present and proposed rates for each customer rate schedule. The proposed revenue increase by class and corresponding percentages are also shown.

XI. CUSTOMER BILL IMPACTS

Q. What are the corresponding bill comparisons for Northern's customers served under its various rate schedules?

A. A presentation of the billing impacts based on class average monthly usage by winter and summer seasons, and presented in deciles of usage, are provided for all rate schedules in Schedule RAJT-13, Customer Bill Impacts.

Q. Has Northern prepared additional bill comparisons for its Residential customers?

A. Yes. The annual bill impacts, as shown on a month-by-month basis, for the Residential rate schedules are provided in Schedule RAJT-14, Residential Customer Bill Impacts.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.