STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Keyspan Gas East Corporation for Gas Service.	Case 16-G-0058
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of the Brooklyn Union Gas Company for Gas Service.	Case 16-G-0059

DIRECT TESTIMONY
OF
UIU RATE PANEL

Dated: May 20, 2016
Albany, New York

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I. INTRODUCTION AND OVERVIEW

Q. Would the UIU Rate Panel please state their names and business address?

A. **(Johnson)** My name is Ben Johnson, and my business address is 5600 Pimlico Drive, Tallahassee, FL 32309.

(Panko) My name is Danielle M. Panko, and my business address is 99 Washington Avenue, Suite 640, Albany, NY 12231.

Q. By whom are you employed, in what capacity, and what are your professional backgrounds and qualifications?

A. **(Johnson)** I am employed as a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation. I received a Bachelor of Arts degree in Economics from the University of South Florida, and both a Master of Science in Economics and Doctor of Philosophy in Economics from Florida State University.

Over the course of more than 40 years, I have been actively involved in more than 400 regulatory dockets, involving electric, natural gas and other utilities. I have presented expert testimony on more than 250 occasions, before federal regulatory agencies, various state courts, and regulatory commissions in 40 states, two Canadian provinces and the District of Columbia.

The majority of this work has been performed on behalf of regulatory commissions, consumer advocates, and other government agencies involved in regulation, but our firm has worked for other types of clients as well, including large industrial consumers and non-profit entities like the AARP and the North Carolina Sustainable Energy Association ("NCSEA").

(Panko) I currently hold the position of a Utility Analyst with the Utility Intervention Unit ("UIU") of the New York State Department of State's Division of Consumer Protection. I received a Bachelor of Science in Mathematics from the State University of New York at New Paltz in 2001 and a Master of Science in Electrical Engineering from the State University of New York at New Paltz in 2008.

From 2000 to 2001, I served as an intern with Central Hudson Gas and Electric Corporation located in Poughkeepsie, New York, in the Accounts Service Department and subsequently in the Electrical Engineering Department. From 2004 to 2007 I worked as an engineer for Philips Semiconductors. From 2007 to 2012, I worked for Consolidated Edison Companies of New York, Inc. in the Rate Engineering Department as an Analyst, and later a Senior Analyst, in the Gas Rate Design Section. I joined the UIU in 2012, where I currently serve as a Utility Analyst III. My primary responsibilities include assisting with UIU's participation in Public Service Commission ("PSC" or "Commission") proceedings, researching utility policy and regulatory related issues, and representing UIU during various utility-related meetings and rate case negotiations. Recent gas cases that I have worked on include Cases 15-G-0284, 15-G-0286, 14-G-0319, and 13-G-0031, in addition to over a dozen other rate and policy proceedings.

Q. Have you previously testified before the New York State Public Service Commission?

A. **(Johnson)** Yes. I previously submitted testimony in Cases 13-E-0030 and 13-G-0031 involving Con Edison, in Cases 14-E-0493 and 14-G-0494 involving Orange and Rockland Utilities, in Cases 15-E-0283 and 15-G-0284 involving New York State Electric & Gas Corporation, and Cases 15-E-0285 and 15-G-0286 involving Rochester Gas and Electric Corporation.

(Panko) Yes. I previously submitted testimony in Cases 13-E-0030, 13-G-0031, 14-E-0318, 14-G-0319, 14-E-0493, 14-G-0494, 15-E-0283, 15-G-0284, 15-E-0285, and 15-G-0286.

Q. What is the nature of this testimony?

A. We will focus on some key aspects of the tariff changes requested by Keyspan Gas East Corporation d/b/a National Grid (“KEDLI”) and Brooklyn Union Gas Company d/b/a National Grid (“KEDNY”) (together, the “Companies”). Although we reserve the right to respond to testimony filed by other parties concerning other topics, our direct testimony is primarily focused on the Companies' embedded cost of service (“ECOS”) studies, their marginal cost of service (“MCOS”) studies, and certain aspects of the Company’s rate design that should be improved in order to better advance the Commission's policy goals. Consistent with this focus, we recommend various changes to the Companies' current and requested rates, particularly with respect to the Companies’ proposed allocation of an excessive share of the revenue burden to small commercial and residential customers, the balance between fixed monthly rate elements (customer charges) and volumetric rates, and the rates charged for temperature-controlled ("TC"), interruptible ("IT"), distributed generation ("DG") and electrical generation ("EG") service. We also offer some brief comments concerning the ratemaking treatment of revenues received from TC, IT, DG and EG service.

Q. How is your testimony organized?

A. Our testimony has seven sections. This first section is an introduction to the forthcoming testimony. In the second section, we briefly summarize our recommendations. In the third section, we briefly discuss the background of this current set of proceedings; the Companies' previous rate cases, which were initiated in 2006 and resolved by a Multi-Year Rate Plan in 2007 (hereinafter "prior rate cases"); and KEDNY's 2012 proceeding (Case 12-G-0544) which stabilized rates for two additional years.

In the fourth section, we discuss ECOS and MCOS studies. We discuss the context of these studies, including some key differences between embedded and marginal costs, the treatment of various "fixed" or "joint" costs in the ECOS and MCOS studies, and how the application of these cost analyses can support or detract from efforts to advance various policy goals. We then discuss in detail deficiencies in the Companies' cost of service studies' methodologies and application, and note the particularly significant impacts of those flaws on the residential and small commercial customers whose interests UIU represents in these proceedings. Finally, we recommend alternative cost of service approaches that are more methodologically sound and would better advance policies to encourage more efficient use of energy and empower customers by giving them more control over their energy costs.

In the fifth section, we discuss the Companies' proposed revenue allocation. In the sixth section we discuss the Companies’ current rate design for gas residential and small commercial customers, and we examine key aspects of the Companies' rate and tariff proposals in these proceedings as they affect these customers. We explain certain problems with both the current and proposed rates and provide recommendations for how the Commission could improve the Companies' rate design to be more equitable and more consistent with the Commission's stated policy goals, particularly with respect to the encouragement of conservation and energy efficiency. Finally, in the seventh section we discuss the rates charged for TC, IT, DG and EG service, and the Companies’ proposals with regard to the ratemaking treatment of revenues received from these services.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes, Exhibit __ (URP-1), Exhibit __ (URP-2), and Exhibit ___ (URP–3) accompany our testimony.

Q. Would you please describe each Exhibit?

A. Yes. Exhibit ___ (URP-1) contains five schedules pertaining to KEDLI's request to modify its rates for gas delivery service. Schedule 1 shows the relative magnitudes of various allocation factors for residential, general service and other customer classes. Schedule 2 summarizes the results of the ECOS study submitted by KEDLI as well as the analogous results using two other approaches to the classification and allocation of certain fixed costs that we will be discussing in detail (the "disputed costs"). Schedule 3 succinctly compares the prices paid by different customer classes, based upon the "effective rate per therm." Schedule 4 shows the current and proposed rate design for various customer classes. Schedule 5 focuses on the current and proposed customer charges (the monthly rate element that is the same regardless of how much the customer uses) and compares them to an estimate of the corresponding customer costs.

Exhibit ___ (URP-2) contains five schedules that are analogous to those in Exhibit ___ (URP-1), except they pertain instead to KEDNY's tariffs and service. Finally, Exhibit ___ (URP–3) contains 33 pages of responses to Information Requests ("IR") referenced in our testimony.

II. SUMMARY OF RECOMMENDATIONS

Q. Please briefly summarize your recommendations.

A. Our recommendations, presented in the order in which they are discussed in our testimony, are as follows:

Gas Cost of Service

We recommend the Commission reject the Companies' proposed method of allocating the costs of gas distribution mains in their ECOS studies. The method the Companies propose tends to allocate an excessive share of certain disputed costs onto small commercial and residential customers. Instead of accepting the approach proposed by the Companies, the Commission should allocate all of these disputed distribution costs based upon the demands placed on the distribution system by each customer class. We offer two alternative ways of implementing this recommendation. Both methodologies ensure that smaller usage customers are not burdened with an excessive share of the fixed costs of the distribution system. Our first alternative analyzes the disputed costs using a methodology which has previously been accepted by the Commission and Department of Public Service ("DPS") Staff in other New York State proceedings, and has been widely accepted in other states. Our second alternative helps illuminate some concerns with regard to setting interruptible and curtailable rates on a cost-of-service basis.

Gas Revenue Allocation

There is no need to drastically adjust the existing revenue relationships based on the Companies' ECOS results, since it is merely a tool that should constitute only one part of the overall ratemaking process. Where the results of that tool show very substantial discrepancies in the degree to which various customer classes contributing their fair share of the system costs, it is reasonable and appropriate to take that information into account when setting rates in these proceedings. However, where the discrepancies are small, or dependent upon aspects of the ECOS methodology which are unreliable or disputed, it is reasonable to use a more across-the-board approach to distributing the revenue burden, giving reduced weight to the ECOS results.

Depending upon the magnitude of the overall rate changes approved by the Commission, it might be feasible to modify the allocation of revenues to the various classes to move into closer alignment with the ECOS results without placing an undue burden on any one group of customers. Needless to say, the direction and extent of any such attempt at realigning rates will depend heavily on the methodology used in developing the ECOS study. In our view there is no need to rapidly adjust the existing revenue relationships, nor would it be appropriate to do so – and the realignment process should not be based upon an ECOS methodology that places an excessive burden on residential and small commercial customers.

Rate Design

Gas Customer Charges and Volumetric Rates

We agree with the Companies' proposal to hold constant customer charges for KEDLI's Service Class ("SC") 1B (heating), SC-1DG, SC-2A (non-heating), SC-2B (heating), SC-3A & B; and KEDNY's SC-1B (heating), SC-2-1 and SC-2-2, and SC-3 customers. However, we have concerns about the Companies' proposals to increase customer charges for SC-1A (non-heating) customers. Instead, we recommend that, depending on the final revenue requirement and amended cost of service results, it may be appropriate to reduce the customer charges for those service classes whose customer charges exceed customer costs, thereby improving fairness and sending stronger price signals to encourage energy efficiency and conservation. For certain classes that are currently using a declining block rate design, we also propose flattening the block rate structure, for much the same reason. Additionally, we recommend that the Companies implement a detailed study to better understand usage characteristics and behavior which can be used to evaluate alternative rate design structures.

TC, IT, DG and EG Rates and Ratemaking Treatment

We believe it is reasonable to continue to use value-of-service as the primary basis for setting these rates. We recommend these customers continue to receive a reasonable discount relative to the rate they would pay if they were to receive firm service. The Companies have presented no evidence that indicates the existing discounts are too small, or need to be significantly increased – either to ensure these customers are treated fairly, or to discourage them from switching to an alternative fuel.

Because two of the main criteria for setting interruptible rates are to ensure that a reasonable discount is offered for non-firm service relative to the analogous rates charged for firm service, and to ensure that a reasonable contribution is provided by non-firm customers for the benefit of firm customers, it would be logical and reasonable to increase the rates charged non-firm customers at the same time that rates are being increased for firm customers.

In determining the specific percentage increase to be paid by non-firm customers, little or no weight should be given to the ECOS results, as so few costs are allocated to these customers under standard allocation methodologies. Instead, we recommend the Commission increase the non-firm rates to a moderate extent, while maintaining a reasonable discount relative to firm service, with the precise percentage increase depending upon the revenue requirement approved by the Commission.

III. BACKGROUND

Q. Please briefly summarize the outcome of the Companies' previous rate proceedings, initiated in 2006.

A. In its Order Adopting Gas Rate Plans for Keyspan Energy Delivery New York and Keyspan Energy Delivery Long Island, issued and effective December 21, 2007 in Cases 06-G-1185 and 06-G-1186, the Commission increased revenues for KEDLI by a modest amount and left KEDNY's revenues unchanged, due in part to recognition of cost savings and efficiencies associated with the National Grid/KeySpan merger. The Order also established a multi-year rate plan that ensured nearly stable base delivery rates for all major categories of customers for at least five years.

Q. Please briefly summarize the outcome of Case 12-G-0544 (*In the Matter of the Commission's Examination of the Brooklyn Union Gas Company d/b/a National Grid NY's Earning Computation Provisions and Other Continuing Elements of the Applicable Rate Plan*), which was initiated due to KEDNY earning above its approved Rate of Return during the prior five years.

A. In its Order Adopting Terms of a Joint Proposal, issued and effective June 13, 2013, the Commission continued KEDNY's existing rates for two additional years, while reducing its allowed return on equity from 9.8% to 9.4% and increasing its common equity capital structure from 45% to 48%. The Commission also adopted modifications to the Company's deferral mechanisms, performance metrics, and revenue requirement.

Q. Would you now provide some background information concerning the current cases as it relates to your testimony?

A. Yes. Notwithstanding its overearning in recent years, KEDNY now projects a revenue deficiency of $245 million in the rate year, and KEDLI projects a deficiency of $142 million. On this basis, KEDNY and KEDLI seek to increase their base delivery rates by more than 30% and more than 26%, respectively.

If approved, the requested rate changes will impact approximately 581,000 KEDLI gas customers, of which approximately 95,000 (16%) are residential accounts that use gas for purposes other than heating (SC-1 A), and approximately 427,000 (74%) are residential accounts that use gas for heating

(SC-1 B). Similarly, the requested rate changes will potentially impact approximately 1,251,700 KEDNY customer accounts, of which 570,000 (46%) are SC-1 A residential non-heating, and approximately 609,000 (49%) are SC-1 B residential heating. The majority of the remaining accounts are small commercial customers, although both utility companies serve a variety of other customers, including government accounts, large commercial and industrial customers and electric generators. Although relatively few in number, these other customers collectively receive a large fraction of the total gas volumes that are delivered over the KEDNY and KEDLI systems.

The rate increases proposed for some types of customers differ from the overall average increase, reflecting decisions made by the Companies in developing and applying their ECOS and MCOS studies. Since the Companies' revenue allocation and rate design proposals are at least partly driven by some key decisions they made in developing their ECOS studies (and, to a much lesser extent, their MCOS studies), we will discuss the cost issues first, before turning to the remaining issues.

IV. COST OF SERVICE

A. Background

1. Introduction

Q. Before going into depth on cost of service issues, would you provide a few brief introductory comments concerning KEDLI and KEDNY's ECOS studies?

A. Yes. The Companies' ECOS studies provide the underlying foundation for the Companies' proposed revenue allocation (distributing the revenue requirements among different customer classes) and some key aspects of their rate design proposals. The ECOS studies were developed using a three-step process.

In the first major step – called "functionalization" – costs are organized based upon various operating functions (e.g., transmission, distribution, customer accounting and customer service). In the second major step – called "classification" – costs are grouped into three classifications: demand-related, commodity-related, and customer-related.

The third major step – called "allocation" – is where specific data are selected and used to allocate costs to specific groups of customers. This step involves the development and application of various percentage factors to spread costs to particular customer classes and rate schedules. The allocation factors are derived from various data sources, and they tend to closely track the initial decisions concerning how costs are functionalized and classified. For example, the investment in Liquefied Natural Gas ("LNG") plant was allocated to different classes based upon their respective levels of winter peak season usage – essentially, the demand placed on the system by each class during an average winter day.

Although the mechanics of this process are well-established and are not controversial, the results of the process will vary widely depending upon specific judgments that are made during the classification and allocation process –

judgments which have been the subject of much debate and controversy throughout the last 40 years, if not longer.

The initial functionalization step tends to be the least controversial part of the process. The second step, classification, is where much of the controversy is often centered. The final step, allocation, also tends to be controversial, because a variety of different peak allocation factors can be chosen to allocate demand-related costs, and because the impacts of disputed judgments made during the second step tend to show up during this final step.

In these cases, one particularly controversial aspect of the classification and allocation process was the Companies' decision to classify certain costs as "customer related" and to therefore assign these costs to customer classes largely on the basis of the number of customers in each class. This has the effect of burdening residential and small commercial customers relative to other, larger customers.

The Companies' approach is apparently founded on this understanding of the purpose of the gas distribution system:

> The Company's gas distribution system is designed to meet three primary objectives: 1. Connect customers to the Company's distribution system; 2. Meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day; and 3. Deliver natural gas commodity to customers, whether they are sales or transportation customers.
>
> Based on these objectives, each functionalized cost element is classified as being customer-related, demand-related, or commodity-related, depending on which of the foregoing objectives it serves.
>
> (Direct Testimony of KEDNY Rate Design Panel, p. 14)

However, this understanding of the purpose of the system is fundamentally flawed. It involves elements of logical circularity, confusion between primary and secondary objectives, and confusion between objectives and constraints.

From an economic perspective, it is clear the distribution system has just one primary purpose: delivering energy to customers. Of course, to receive this energy, customers need first to be connected to the system. But it is inherently circular to suggest that one of the purposes of the distribution system is to connect customers to the distribution system – any such connection is a means to an end, not an end unto itself. More precisely, we can say that the distribution system includes service lines that connect customers to distribution mains. The distribution mains connect to transmission mains, which in turn connect to a source of natural gas. The entire system is designed to efficiently move gas from its source to the location where it will be burned.

Similarly, while one can argue that certain costs are customer-related to a greater degree than other costs – e.g. components of the system that are physically located on the customer's premises – this does not mean that other factors aren't involved in determining the magnitude of those costs, or determining whether they will be incurred. Meters are a particularly clear example. The number of meters is very highly correlated with the number of customers; no one disputes that meter costs are customer-related, at least in part. But meter costs are also energy-related – indeed, meters would not even be needed if every customer used the exact same amount of energy. Furthermore, gas meters are also somewhat demand-related, as more expensive meters are required to accommodate those customers that use large volumes of gas during peak periods.

There is an inherent arbitrariness in trying to force costs into a simplistic classification schema when those costs are actually incurred as part of a complex, multi-dimensional process that involves important factors that cannot easily be attributed to specific customers or customer classes. While we specifically object to the arbitrary results of this simplistic approach with respect to certain disputed costs that are being classified as “customer-related,” it is worth noting that the problem is not unique to “customer-related” costs. A similar problem would arise if the revenue allocation and rate design process were founded on a cost study in which one of the key steps involved classifying certain costs as safety related. Some costs (e.g. inspections) might unambiguously be characterized as safety-related, but this would not mean that all other costs are completely unrelated to safety, nor would it mean that the costs classified as being safety-related (e.g. inspections to find leaks) would be unrelated to, or have no benefits with respect to, any other purpose (e.g. maintaining a clean environment). Nor would the classification of only certain costs as safety-related change the fact that other costs are (in reality) also influenced by safety requirements, even if the primary purpose lies elsewhere.

The Companies chose to classify a large fraction of delivery costs as “customer-related.” They consequently allocated most of these costs to classes with the largest number of customer accounts, and this led them to design rates that place a greater burden on smaller customers relative to larger customers. They explain their reasoning as follows:

> Customer-related cost elements are a function of the number of customers served and are incurred by the Company whether or not an individual customer uses any gas. They may include capital costs associated with the customer component of distribution mains, as well as costs for services, meters and metering, billing, customer service, and accounting and collection activities.
>
> (Direct Testimony of KEDNY Rate Design Panel, pp. 14-15.)

This approach effectively treats a large portion of the costs of the distribution system as “fixed” costs to be allocated and recovered on a relatively uniform per-customer basis, and assumes that only the remaining, “variable” costs ought to be allocated and recovered on the basis of energy deliveries or demand placed on the system. We disagree with this approach both on theoretical grounds and because of its practical effects: it places an unreasonably large share of the overall cost burden on residential and small commercial customers, and it weakens the incentive for customers to install more efficient appliances or take other actions to reduce their consumption of energy.

We dispute the Companies' treatment of these costs in their ECOS studies, and will be discussing our reasoning in depth further in our testimony. For the moment, it is sufficient to note four issues pertaining to the treatment of so-called “customer-related” costs: First, as a practical matter, this interpretation has a significant impact on the rates paid by small customers relative to the rates paid by larger customers. Second, as a theoretical matter, the extent to which these costs are “fixed” or “variable” differs depending on one’s frame of reference or the time frame under consideration. Third, just because costs are “fixed” does not mean they ought to be allocated or recovered on a per-customer basis.

Fourth, most of the fixed costs in question do not directly vary with the number of customers, and this is true regardless of time frame. In fact, these so-called "customer-related" costs tend to vary with demand, peak usage, and energy consumption over the long run. In other words, the concepts of "fixed" costs and "customer" costs are not equivalent, and even where a cost is not variable, this does not logically determine whether that cost should be allocated or recovered on a per-customer basis.

Q. In wrapping up this initial introduction to the Companies' cost studies, would you please briefly discuss KEDLI and KEDNY's MCOS studies?

A. Yes. Both Companies submitted MCOS studies, but they placed very limited reliance on these studies, and many of the key numbers included in the MCOS studies are derived from the respective ECOS studies. Hence, our comments concerning marginal costs will be relatively brief.

2. Embedded versus Marginal Costs

Q. Can you briefly explain the difference between embedded and marginal costs?

A. Yes. There are three fundamental differences between embedded and marginal costs, which are respectively reflected in the ECOS and MCOS studies.

First, and most fundamentally, embedded costs are derived entirely from the accounting records of the firm, and are heavily influenced by and dependent upon the conventions adopted by the firm in books and records. In contrast, marginal costs are derived from economic theory – they are based upon well-understood concepts in the economic literature and can be estimated using data from a variety of different sources including, but not limited to, accounting data and various types of special studies.

Second, although marginal costs are particularly important, they are just one part of a highly refined understanding of costs that has provided a fundamental foundation for much of the progress that has been made in microeconomic theory and empirical research over the past 100 years.

Third, a typical ECOS study is focused on allocating costs, whereas a MCOS study does not (or at least should not) primarily focus on allocations. Because an MCOS study is intended to estimate marginal costs, it attempts to estimate the extent to which the total costs (of the firm or of society) vary in response to changes in output.

3. Marginal, Variable, Fixed, and Total Costs

In economics, the most fundamental and important types of costs are fixed cost, variable cost, total cost, average cost, marginal cost, incremental cost, and stand-alone cost. All of these are integral parts of economic theory – although there are other, more specialized cost concepts that are also important in the current context, including sunk cost, direct cost, joint cost, and common cost.

Fixed costs do not change with the level of production, during the planning time period under consideration. Variable costs change directly (but not necessarily proportionately) with the level of production. Together, these constitute total cost, which is the sum of all costs incurred by the firm to produce any given level of output. Dividing the total cost of producing a given quantity of output by the total number of units produced, one can calculate average total cost.

Long-run costs are those calculated under the assumption that most, if not all, costs are variable; and few, if any, are fixed or sunk. In contrast, short-run costs are those that arise in situations where most costs are fixed. The classic long-run concept is sometimes known as a "scorched earth" approach - that is, no pre-existing plant is considered in the analysis. Instead, the firm is free to build precisely the size and type of plant that best fits the assumed output level.

Incremental cost is the change in total cost resulting from a specified increase or decrease in output. In mathematical terms, incremental cost equals total cost assuming the increment of output is produced, minus total cost assuming the increment is not produced. Incremental cost is often stated on a per-unit basis, and the change in cost divided by the change in output. Incremental cost can vary widely, depending upon the increment of output under consideration. If the entire increment from zero units to the total volume of output is considered, incremental cost is identical to total cost. Similarly, where the increment ranges from zero to total output, incremental cost per unit is identical to average cost per unit. Because a wide variety of different increments can be specified, a wide variety of different incremental costs can be calculated. Thus, in considering any estimate of incremental cost, it is crucially important to determine whether or not the specified increment is relevant to the issues at hand.

Marginal cost is the same as incremental cost where the increment is extremely small (e.g., one unit) and the cost function is smooth and continuous. In mathematical terms, marginal cost is the first derivative of the total cost function with respect to output -- that is, it is the rate of change in total cost as output changes. Conceptually, marginal and incremental costs are very similar;

however, there is a wide array of incremental cost concepts, corresponding to the wide array of possible increments that can potentially be analyzed. In contrast, marginal cost corresponds to one small portion of this array -- where the increment is narrowly defined and extremely small.

One aspect of MCOS studies that should always be carefully scrutinized is the manner and extent to which particular costs are being treated as variable or fixed – something which is often closely related to assumptions or judgments related to the planning time period. In the context of gas storage, transmission and distribution systems, most costs vary little over the short-run, so short-run marginal cost tends to be low – sometimes approaching zero. In contrast, all costs are classified as variable in the long-run, so long-run marginal costs tend to be much higher than short-run marginal costs. In practice, decisions made by the analyst concerning the appropriate time period and the extent to which specific costs are interpreted as being variable or fixed will often strongly influence – if not entirely determine – the results of an incremental or marginal cost study.

It is also important to realize that costs do not necessarily vary along every dimension of the cost function, nor do they necessarily vary on a proportional basis. This important caveat has many interesting implications – including the possibility that significant discrepancies can arise between costs per unit that are developed on an average basis, and costs per unit that are developed on an incremental or marginal basis. For instance, while the investment in a gas distribution main would be considered "variable" in the long run, that does not mean these costs would necessarily vary in proportion to changes in the volume of gas carried (or expected to be carried) through the main, even in the context of a long-run analysis. It may be the case that a larger main can be installed, capable of handling double the volume of gas, at a cost that is nowhere near double the cost of the smaller main.

Due to economies of scale and scope, the incremental investment attributable to an incremental service or group of customers may be substantially lower than the average investment required to serve other customers – assuming those other customers are not being treated as “incremental” in a particular context. This discrepancy tends to be particularly pronounced in incremental cost studies in which some capital costs are interpreted as being fixed – in effect, studying the short to medium-run. A somewhat similar phenomenon can sometimes be observed in marginal cost studies. A particular portion of the firm's overall output (e.g., service provided to certain customers, or a particular aspect of the service provided to certain customers) might be treated differently than other portions of the firm's output, resulting in corresponding discrepancies in the resulting marginal cost estimates – depending upon the manner in which economies of scale and scope are handled, or differences in the manner in which variable and fixed (or sunk) costs are handled.

For example, in a long-run study, where capital investment is treated as variable and technological improvements have not been sufficient to offset the impact of inflation, a group or service that is viewed as “incremental” may appear to have much higher costs than other customers or services. The reverse might be true in a short- to medium-run study. In cases where a substantial portion of the firm's capital investment is assumed to be “sunk” or fixed, whichever category or group is treated as variable or “at the margin” may appear to have relatively low costs, at least in comparison with the average cost of providing service to other categories. What is sometimes not realized, however, is that this pattern is often easily reversible by simply switching which service or customer group is considered “incremental” or “marginal.”

4. Fully Allocated Embedded Costs

Q. Please elaborate on the purpose of fully allocated embedded cost studies, and explain some of their limitations.

A. Fully allocated cost of service studies divide total test-year revenues, rate base, and operating expenses among the various customer classes to estimate the rate of return earned from each class. These types of studies have long been used by this Commission and other regulators as a tool to assist with developing electric and gas rates. As long as their limitations are recognized, and reasonable allocation formulas are employed, fully allocated ECOS studies can be useful in determining an appropriate distribution of the revenue requirement amongst the various customer classes.

However, because delivery rates are based upon embedded costs, these studies do not always report direct cause-and-effect relationships between the consumption decisions of the class members and the costs incurred by the utility. Thus a "cost" identified in the study is not necessarily the actual expense that a particular group of customers causes or imposes on the system, or a measure of the amount by which total costs would be reduced if that customer or group of customers were to leave the system. Although people sometimes speak of ECOS studies as reflecting "cost-causation," this is only true to a limited degree.

The extent to which a study reflects cause-and-effect relationships varies with the category of costs in question, and the allocation factors chosen by the analyst. The relationship is most attenuated, and the degree of arbitrariness or subjectivity is most serious, when dealing with the portion of the utility's revenue requirement that reflects those fixed costs which economists would define as "joint" or "common" costs. Joint and common costs (as economists define these terms) cannot be directly traced to any one class. These costs are neither caused by, nor are unambiguously attributable to, any specific customer class. These costs must be allocated by a formula based upon subjective judgments that largely control the final outcome. The final results depend on how joint and common costs are initially classified, as well as the specific allocation formulas chosen by the analyst (which generally follows from decisions made during the classification process).

Q. Can subjective judgment and arbitrariness be entirely eliminated if the analyst is completely unbiased and sufficient effort is applied to the task?

A. No. ECOS studies are simply a tool for evaluating the relative fractions of the total revenue requirement that can reasonably be recovered from each class. At best, these studies provide a helpful yardstick for judging whether or not each customer class is paying a reasonable and appropriate share of the joint and common costs. The real question is whether the yardstick is reasonably straight and true, or whether it is bent to favor particular classes at the expense of others.

Widely differing results can be developed for the same set of customers depending upon the particular year in which the costs are studied, the quality of the load research data and other inputs used, and/or the particular allocation approach used in preparing the study. When there is a dispute concerning the results of an ECOS (as there is in this case), the underlying source of the dispute is rarely with the people performing the studies or with the amount of effort and resources devoted to the analysis. Rather, it is inherent in the very concept of allocating embedded costs, and the decisions that are made concerning how to classify and allocate costs that are not readily traceable to specific customers or customer classes.

B. Disputed Category of Costs

Q. Do you have any fundamental disagreement with the Companies' embedded cost studies and corresponding rate proposals?

A. Yes. We strongly disagree with the manner in which certain allegedly "customer-related" costs are being handled in the Companies' ECOS studies and rate proposals. We believe sound principles of cost-causation are not being followed, and as a result too much of the joint and common cost burden is being placed on small residential and commercial customers. In turn, the Companies are proposing rates that are not consistent with the manner in which these types of costs would typically be recovered in competitive, unregulated markets, and that are not optimal from a policy perspective.

Q. Can you be more specific about the “disputed costs,” which you believe are not being appropriately handled in the Companies' ECOS studies?

A. Yes. We disagree with the proposed treatment of Account 376: Distribution Mains. KEDLI proposes to classify 58.35% of these costs as “demand” related and 41.65% as “customer” related. This leads it to allocate 41.65% of these costs – approximately $732 million, or $578 million net of depreciation – largely in proportion to the number of customers in each class. Similarly, KEDNY proposes to classify 62.09% of Account 376 as “demand” related and 37.91% as “customer” related. This leads it to allocate approximately $832 million, or $687 million net of depreciation – largely in proportion to the number of customers in each class. This FERC Account comprises a very large portion of the Companies’ rate bases, so this disputed aspect of the Companies’ ECOS studies (and related aspects of the Companies’ proposed revenue allocation and rate design) is highly significant.

Q. Have the Companies explained why they propose to classify and allocate these costs in this manner?

A. Yes. KEDLI's Rate Panel explained the decision-making process as follows:

> Distribution mains are installed to connect customers to the distribution system (i.e., customer-related), as well as to provide capacity to meet customer requirements on the design day (i.e., demand-related). Therefore the cost of mains is classified as partly customer-related and partly demand-related. The Company estimated the customer component of mains to be approximately 41.65 percent based on the results of its minimum-system study. The customer component was allocated among the customer classes based on the number of customers. The demand

> component was allocated among the customer classes based on their contribution to design-day demand.
>
> (Direct Testimony of KEDLI Rate Design Panel, pp. 16)

A similar description can be found on page 16 of KEDNY's Rate Design Panel Testimony. The pre-filed testimony included a follow-up question, in which the Rate Panel was asked more specifically about how the "minimum-system" study was prepared. In response, the Panel offered some general comments attempting to justify their approach, and a few details concerning the mechanics of the procedure they used in arriving at the proportion of so-called customer-related costs:

> Minimum-system studies are a widely accepted method to classify mains between customer- and demand-related costs. The customer-related component is the portion of cost representing the least-cost system the utility would install simply to connect customers, without regard to the need to meet demand....
>
> The minimum system ratio is computed as the ratio of X, the cost (in 2015 dollars) of replacing the entire mains distribution system with two-inch plastic, to Y, the cost (in 2015 dollars) of replacing the entire mains distribution system with plastic of the same diameter as-installed.
>
> This produced a minimum system ratio overall of 41.65 percent, which represents the portion of total mains cost simply to connect customers without regard to meeting their design-day demands (i.e., customer-related costs).
>
> (Id. at p. 22.)

While they explained the mechanics of their calculations, they have offered very little in the way of evidence or logic to support their approach, aside from noting they used a “widely accepted” method. If the Rate Panel has the impression that this treatment of the disputed costs is the only “correct” way to handle Account 376, they are mistaken. While minimum system studies are used by some other utilities, it is also fair to say they are “widely rejected” – in many areas they are not used at all, and elsewhere they have often been proposed by utilities and rejected by regulators.

Q. Would you explain some of the reasons why you disagree with allocating or recovering the disputed costs on a per-customer basis?

A. Yes. We will readily concede that most of the costs in Account 376 are fixed. These costs do <u>not</u> vary in the short run, and even in the long run the cost of distribution mains does not on vary in exact proportion to gas handling capacity, because of economies of scale. That does not mean, however, these costs should be recovered primarily from small customers. No matter how elaborate and detailed the calculations, any analysis of the cost of a hypothetical “minimum system” falls flat as a logical justification for putting more of the cost burden on small customers, because there is no causal connection between the identified costs and the number of customers served by the system. At best these calculations help the analyst understand and quantify economies of scale, with the “minimum system” representing an estimate of costs that are fixed with respect to gas-carrying capacity, and the remainder of the costs representing the portion of the cost of the distribution mains that varies as a function of the size of the lines (i.e., the volume of gas they can accommodate).

The key point to realize is that the "minimum system" calculations help identify fixed costs, but these costs do <u>not</u> vary as a function of the number of customers – even in the long run. Rather, in the long run, the minimum cost of the distribution system varies as a function of the number of miles of streets served by the system, and the remaining cost (in excess of the minimum) primarily varies with the anticipated peak load that each main is expected to accommodate over its useful life (which can be 40 or more years).

Because these facilities are engineered on the basis of maximum peak load, the costs in Account 376 are often allocated entirely on the basis of peak load data for the various customer classes. This is the approach used by utilities and by regulators in many other states. Even in New York, this approach has been used or endorsed by other utilities and the DPS Staff in some other cases. For example, the DPS Staff classified Distribution Mains (Account 376) as 100% demand-related, to be allocated using some version of peak usage data, in the most recent Orange and Rockland gas rate case (14-G-0494), as well as in some past cases involving KEDNY and KEDLI (06-M-0875, 06-G-1185, and 06-G-1186). Similarly, New York State Electric and Gas and Rochester Gas and Electric classified 100% of Account 376 as demand-related in several different proceedings, including cases 09-G-0716, 09-G-0718, and 01-G-1668.

The costs in question do not vary in proportion to the number of customers on the system, and there is no compelling economic reason to recover these costs on a uniform per-customer basis. In our view, these costs should be recovered in a manner that best achieves the Commission's policy objectives, consistent with the economic principles applicable to joint cost recovery.

Q. How does this issue relate to your earlier discussion of joint and common costs?

A. The costs in these accounts can appropriately be viewed as joint or common costs. More specifically, the “minimum system” portion (e.g. the cost of trenching) can appropriately be seen as joint costs, while costs in excess of this minimum (i.e., the cost of installing larger pipes that are capable of distributing larger volumes of energy) are generally costs that are incurred in common to serve multiple different customers or customer groups. These common costs will vary in the long-run depending upon the volume of energy that will be consumed by the utility's customers, and when that energy will be needed (as it is more costly to deliver a given volume of gas during peak periods, when many different customer classes tend to have high demand for energy).

Q. Regulators sometimes use the desirable results of effective competition as a benchmark to help guide their regulatory decisions. How are joint and common costs recovered from customers in competitive markets?

A. In competitive markets, to the extent common costs vary with output, they are recovered in the same manner as direct costs: common costs directly affect the marginal cost of producing each service, and thus directly influence prices. (In competitive markets, prices tend to equilibrate towards marginal cost). Joint costs, on the other hand, have no impact on marginal cost, and these costs do not directly determine prices in unregulated, competitive markets. Instead, joint costs are recovered through the prices charged for all of the different products or services produced through the joint production process. The respective proportions will vary depending upon supply and demand conditions generally, the degree to which purchasers of different products benefit from the joint production process, and the relative strength of demand for the various services or products that benefit from the joint production process.

Stated another way, in competitive markets each customer does not contribute a uniform dollar amount toward the recovery of joint costs without regard to how much of the product they purchase or how much they benefit from the joint production process. Instead, cost recovery varies with larger customers contributing more than smaller customers, and different types of customers contributing different amounts based upon the strength of demand in different markets or submarkets. In general, the stronger the demand – and in that sense, the greater the benefit received from the joint production process – the greater the share of joint costs that will be borne by the respective product, service, or customer group.

Q. Since the disputed costs are joint costs, would you elaborate on how joint costs are recovered in competitive markets?

A. Yes. Two classic examples of joint costs occur in the production of beef and hides and cotton and cottonseed. The costs of raising and slaughtering cattle are part of a joint production process that produces meat and hides. Similarly, cotton and cottonseed oil are both part of a joint production process. In each of these examples the recovery of joint costs takes into account the relative level of benefits enjoyed by the users of the joint outputs. For example, if hamburger is not highly valued, but leather is, then a larger fraction of the cost of cattle feed will be borne by the purchasers of leather goods. Similarly, if the purchasers of gloves are willing to pay more for leather gloves than for cloth gloves, they may end up paying a relatively large share of the cost of cattle feed while the purchasers of cotton gloves may pay a relatively small share of the cost of growing cotton (and consumers of cottonseed oil may pay a larger share than might otherwise be expected).

This well-established insight from the economic literature is intuitively logical and fair. The purchasers of both leather gloves and hamburgers benefit from the joint production process and the demand for both beef and leather products is strong, so it intuitively makes sense that market forces would ensure that both types of customers contribute toward the joint costs. But there is nothing in this analysis to suggest any reason why someone buying a single pair of gloves should contribute the same amount as someone buying a leather coat, or that someone buying a single hamburger should contribute the same amount as someone buying an entire standing rib roast.

This discussion is directly applicable to the issues in dispute in these proceedings. It has long been understood (at least by economists) that different groups of customers share the burden of joint costs in proportions that vary based upon the demand side of the supply and demand equation. Customers do not all pay the exact same amount, regardless of how much they benefit from the joint production process. Instead, those who benefit more from the joint production process (i.e., those whose demand is strong) pay more of the joint costs than those who benefit just a little (i.e., those whose demand is weak).

Q. Are you arguing that the Commission must resolve the cost allocation dispute, or set prices, in exactly the same manner as would occur in a competitive market?

A. No. We view the Commission's role as more flexible, and we believe there are many different factors that merit consideration in setting regulated prices. While the Commission does not need to precisely follow the example of how joint costs are recovered in unregulated, competitive markets, we think the patterns observed in these markets are both relevant and instructive.

There is no logical reason to recover most of the joint costs from small customers merely because there are more of them, nor is there any logical reason to recover a similar amount of joint costs from large customers as from small ones. This would completely ignore the vast differences in benefits received from customers of vastly different size, which is contrary to the normal outcome in competitive markets, where customers who value the product the most, or purchase the largest quantity, typically pay a larger share of joint costs than customers who buy less, or value the product less. As it happens, this normal competitive outcome is consistent with other important policy goals, like the encouragement of economic efficiency and energy conservation, and we see no reason to deviate from this normal outcome by forcing small customers to pay an inordinately large share of the joint cost burden. Our recommended approach, discussed below, helps achieve the Commission's policy objectives, and it is more consistent with the typical pricing practice in competitive markets.

C. Cost Causation

Q. It might be argued that the Companies' "minimum system" approach better conforms to the principle of cost causation. What is your response?

A. We strongly disagree. To begin with, we would note that the cost of a hypothetical "minimum system" cannot readily be traced to the number of customers on the system. In fact, to a large extent these costs cannot be traced to any readily available data that is useful in developing an allocation study, because a substantial fraction of the costs incurred in these accounts are fixed costs that do not vary with usage, the number of customers, or any other straightforward data set, rather they primarily vary with the number of miles of streets and roads where gas service is provided. Yet road mileage is not a useful statistic for apportioning costs to different customers or groups of customers.

The “minimum system” approach is essentially reflecting a distinction can between fixed and variable costs in the long run (in the short run the investment in distribution mains is entirely fixed), as well as the existence of economies of scale. However, in understanding what “causes” these fixed costs to be incurred, the number of customers is <u>not</u> the most important variable. In the long-run planning horizon, these costs will vary with the peak volume of energy that is expected to flow through the facilities, and the number of miles of streets along which gas service will be made available. These investments in mains do <u>not</u> vary in proportion to the number of customers along the streets where distribution mains are (or will be) installed.

To the extent the costs in Account 376 varies with something that is easily measurable and can potentially be attributed to specific customer classes, these costs vary with the peak volume of gas that is expected to flow through the facilities. From an engineering perspective (<u>how</u> these costs are incurred), the entire system of distribution mains and services – the pipes running down the street and the pipes running from the street to the buildings – is designed to accommodate peak demands. On that basis, the entire cost of distribution mains is often allocated on the basis of demand (gas usage during peak periods). The argument is straightforward: the system is designed to meet peak demand, so peak demand is the simplest and best proxy for what "causes" these costs to be incurred.

As discussed earlier in our testimony, this approach is widely used in other states, and it has been accepted in several New York proceedings, and we believe it provides a reasonable approach to handling the disputed costs. However, we willingly concede it is not a perfect solution in terms of cost causation. We point this out because a pure, unambiguous cause and effect relationship cannot be drawn between the amount of costs incurred in these accounts and peak demand. The problem is most easily seen in the case of temperature controlled or interruptible customers. These customers are generally assumed to be off-line during the system peak, and thus they are allocated little or none of the disputed costs using a peak allocation approach, yet these customers benefit greatly from using the system – and anticipated revenues from these customers often contributes to the decision to build the distribution main (helps "cause" the costs) in the first place.

Strictly speaking, from an economic perspective (<u>why</u> these costs are incurred), the entire distribution system – including the portions running down the street and the portions running from the street to the buildings – is driven by the consumption of gas. In other words, in a supply and demand sense, that which <u>caused</u> the system to be built is the demand for energy – demand which can efficiently be met by obtaining natural gas at the wellhead, transferring it in bulk to major population centers, then distributing it to various locations where the energy will be consumed. Aspects of this process will vary depending upon the locations where the demand for energy exists, and costs per unit will generally be lower if a system can be configured and built that meets the energy needs of many different types of customers on a combined basis.

Because demand is so important to the engineering and design of distribution mains, it is widely accepted as the basis for allocating the associated costs. However, this doesn't mean that interruptible and curtailable customers should be exempt from making any contribution toward the cost of distribution mains, merely because they don't contribute to peak demand. Consistent with the general principles of joint cost recovery (mentioned above), interruptible and curtailable customers should also defray some of these costs, based upon value-of-service principles, market-based pricing, or the like. We will discuss this topic again later in our testimony.

Q. Would you please elaborate on the concept of a “minimum system” and how it relates to your recommendations?

A. The Companies have relied upon the concept of a hypothetical “minimum system,” arguing that only the “extra” cost of building a larger-than-minimum-scale system can be attributed to variations in peak demand, and that the portion of the cost of the system that is fixed with respect to peak demand should be classified and allocated on some other basis – and they typically advocate using the number of customers for that purpose.

We concede there is some limited merit to this line of reasoning, to the extent it focuses on the fact that there is some “minimum” level of costs that must be incurred to provide energy along any given street. However, identifying the existence of fixed costs associated with some hypothetical “minimum system” does not solve the problem of how to recover these fixed costs, nor does it provide any logical justification for recovering these costs on a per-customer basis. The cost of installing a distribution main does not vary in proportion to the number of customers along any given street, nor does the cost vary depending upon the decisions of individual households and businesses to connect to the system (except to the extent these decisions contribute to a changes in anticipated peak demand, which influences the design of the main).

In truth, there is no straightforward way to attribute the fixed costs of a distribution main (or the cost of a "minimum system") to specific customers or customer groups based on principles of cost causation, because these costs are incurred on an aggregate basis based upon the characteristics of the area to be served – and these aggregate costs do not depend on the number of customers connected to the main.

At the root of this dispute is a difference in philosophy concerning what <u>causes</u> costs to be incurred, and what factors are most important in designing regulated rates. On page 23 of its Smart Rate Design for a Smart Future paper (issued July 2015), the Regulatory Assistance Project explained:

> Most people who have ever tried their hands at designing rates for regulated utilities invariably say that it is "more art than science." Because of the shared nature of the system and the need to spread cost recovery fairly among all customers, the idea that rates should be set based on customer cost causation is a foundational concept in rate design. Analysts who ask, in a causal sense, "why" costs are incurred often reach different conclusions than those who measure, in an engineering sense, "how" costs are incurred.

We agree with these comments, and would further assert that the principle of "cost causation" supports recovering these fixed costs based largely, if not entirely, on the amount of demand placed on the system by different customers. In general, the aggregate demand for energy (and the associated income potential) is the primary factor that influences most decisions to install distribution mains along a given route in the first place, and individual energy usage (and the associated cost savings potential) is what motivates decisions by individual households or businesses to connect to the mains if they are installed.

In contrast, the number of customers does not provide a good proxy for the factors that explain "why" these costs are incurred, since this completely ignores the volume of energy each customer is expected to use, and thus the extent to which there is an economic basis for installing the distribution main in the first place ("why" the main was constructed). Similarly, the number of customers connected to the main completely ignores what size main will be needed ("how" the main is engineered, and thus how much it will cost).

Stated another way, if the system planners anticipate that sufficient economic demand exists for natural gas on the part of households and businesses along a given street, and if that demand is strong enough to justify the investment, the system will be built or expanded along that street. Consider the cost of expanding a gas system into new neighborhoods, or along additional roads where there is no governmental mandate to do so. It will make economic sense to expand the gas system to serve a new area if the planners anticipate that over time enough new buildings will be constructed and connected to the system, and/or enough existing buildings will convert from propane or oil to natural gas, and that these buildings use enough energy. The key question is not simply whether buildings exist along a street (or how many buildings), but whether the owners or tenants use enough energy – whether their demand for natural gas will be strong enough - to justify construction of the system. In essence, the new or expanded system needs to generate enough revenue to cover its costs, and this is directly related to the total demand for natural gas (the volume of energy that will be delivered over the system if it is built).

If the system is built, each building owner or tenant will decide whether or not to connect to the system based on their individual cost-benefit analysis, which will heavily depend upon how much energy they use. A small user who relies on propane may have little or no incentive to connect to the system, whereas a large user will have a much greater incentive to do so, because of the larger potential cost savings from the lower commodity costs associated with natural gas, relative to propane or fuel oil.

D. Recommended Treatment of Disputed Costs

Q. Given the problems with the Companies' "minimum system" approach, what alternative do you recommend?

A. We recommend classifying the entirety of Account 376 as demand-related and allocating it using a peak allocation factor – the Companies' Design Day Demand factor. This approach is widely used by other utilities and regulatory commissions and it offers a reasonable basis for analyzing costs, with the exception of temperature controlled and interruptible customers.

The Companies propose to move certain interruptible and curtailable customer classes from value-of-service based pricing to cost-based pricing, so they included these classes in the ECOS study. We do not think this is advisable, for reasons we will discuss later in our testimony. However, to the extent cost-of-service based pricing is going to be considered as an option, it would not be appropriate to allow these customers to use the transmission and distribution system without being assigned a reasonable share of the cost of this system. The assigned share of investment in transmission and distribution mains approaches zero in the Companies' ECOS studies and in our recommended studies based upon Design Day Demand. Hence, the rate base allocated to these classes is extremely small relative to their size, and thus the calculated class rates of return are inordinately large. However, we don't think the resulting high percentage rates of return are meaningful, nor do they provide an accurate indication of how reasonable the interruptible and curtailable rates are relative to the rates being paid by firm customers (since firm customers are being assigned the full cost burden of mains that are shared by both firm and interruptible customers). We discuss this problem and our alternative ECOS study in greater detail later in our testimony, when we discuss the Companies' rate proposals for temperature controlled and interruptible customers.

Q. Have you estimated the impact on the ECOS results for KEDLI's customers of using these two options?

A. Yes. On Page 2 of Schedule 2 of Exhibit ___ (URP-1) and Exhibit ___ (URP-2) we developed ECOS studies that essentially replicate the data and methodology used by the Companies with one key difference: we classified 100% of the costs in Accounts 367 as “demand-related” and allocated those costs to the various customer classes using the Companies' Design Day Demand allocator.

The results for KEDLI are summarized on Exhibit ___ (URP-1). For ease of development and comparison, these calculations were based on the same overall numbers used by the Companies' Rate Panel in their testimony and exhibits. Thus, for example, the overall rate of return (3.83%) is the same figure used by KEDLI in its study. Using Design Day Demand to allocate all of Account 376 generates noticeably higher or lower rates of return for many of the individual customer classes. For example, the rate of return for SC-1A is 3.53% (close to the system average) using Design Day Demand, compared to -3.82% using the methodology proposed by the Companies.

The impact of this difference in methodology is even more striking in the KEDNY study, as shown on Exhibit ___ (URP-2). The class rate of return for SC-1A is 11.91% (far above the system average) using Design Day Demand, compared to -5.38% (far below the system average) using the methodology proposed by the Companies.

On Page 3 of Schedule 2 of Exhibit ___ (URP-1) and Exhibit ___ (URP-2) we show what happens if 100% of the costs in Accounts 367 are classified as “demand-related” but the “minimum system” portion is allocated using Winter Daily Demand, while the remainder is allocated using the Companies' Design Day Demand allocator. This methodology has the effect of allocating a more significant share of Account 376 to interruptible and curtailable customers, and thus the resulting class rates of returns are somewhat more meaningful – although we still question whether cost-based pricing would be an improvement over value-based pricing for these customers.

V. REVENUE ALLOCATION

Q. How have the Companies proposed to distribute their proposed revenue increase among the various customer classes?

A. Both Companies initially focused on the results of their ECOS studies, but they ultimately decided to increase rates for most classes by a uniform across-the-board percentage amount (31.5% for KEDNY and 26.7% for KEDLI) for residential and small commercial classes (KEDNY SC-1-A&B, SC-2-1&-2, and SC-3 and KEDLI SC-1-A&B, SC-2-A&B, and SC-3). The rationale for this approach is not explained in detail, except that the Companies noted this approach was sufficient to gradually move each service class closer to its revenue requirement as determined in each of the ECOS studies. The exceptions were the TC and IT customers, who were included in the ECOS studies and on the basis of those results were given a lower than average percentage increase during the revenue allocation process.

Q. Can you please discuss your response to the Companies' revenue allocation proposals?

A. We find a great deal of merit to the Companies' approach, since this approach helps maintain a degree of “rate continuity” and it reduces the degree to which flaws in the Companies' ECOS methodology adversely impact individual customer classes. In general, we believe revenue allocation should not be a purely mechanical process that perfectly tracks the results of a particular ECOS study. Instead, we believe thought should be given to the potential hardships imposed on particular classes, historical relationships among the classes, and other elements of interclass equity.

Given the inherent instability and subjectivity of the various allocations, the goal of absolute uniformity in class rates of return can probably never be achieved. Such an effort is an attempt to hit a moving target, and it can potentially conflict with important policy objectives such as rate continuity, gradualism, and stability.

Furthermore, the returns earned by each of the classes depend in large part on the data used in that particular cost-of-service study. In some cases, a class that has an above-average return during one test period might show a below-average return during a different test period. When a proposal would make substantial changes to the existing rate relationships (shifting more costs onto or off of specific classes based on the ECOS results), it is preferable to verify that similar results have occurred in earlier studies. The Companies did not discuss any such studies in their testimony in these proceedings.

Q. Do you agree with the Companies' revenue allocation proposals?

A. No. While we see merit to some key aspects of the Companies' approach, we disagree with some aspects, especially the treatment of non-firm customers, and we disagree with the ECOS studies they relied upon in developing their proposed revenue allocation.

Q. What are your recommendations concerning revenue allocation?

A. First, we recommend against classifying and allocating “minimum system” costs based upon the number of customers, as discussed earlier. We recommend the revenue allocation be based upon a more reasonable approach to cost allocation, as we discussed above.

Second, we disagree with using ECOS results to determine what share of the revenue increase should be borne by TC, IT, DG and EG customers. Under most cost allocation methodologies, virtually none of the costs of the distribution mains are allocated to these customers, even though they benefit greatly from using these mains, so a cost-based pricing methodology is problematic. If for some reason the Commission wants to pursue this proposal, a reasonable share of the costs of the distribution system must be allocated to these customers. For this reason, we developed ECOS results in which the “minimum system” portion of Account 376 is allocated based upon Winter Daily Demand, as shown on Schedule 2, Page 3 of Exhibit ___ (URP-1), and Exhibit ___ (URP-2).

Third, the Commission should make reasonable progress toward reducing some of the substantial deviations that exist in individual class rates of return relative to the overall system average. If a customer class currently pays relatively high rates, and this translates into a class rate of return that is far higher than the overall system average, the Commission should make an effort to constrain the rate increase imposed on those customers. For example, KEDNY's SC-1A Residential Non-Heat customers are paying very high effective rates per therm, as shown on Schedule 3 of Exhibit ___ (URP-1), and these high rates are resulting in a very high class rate of return – 11.91% assuming the disputed costs are allocated using Design Day Demand, or 11.36% assuming the disputed costs are allocated using Winter Daily Demand. Similarly, if a customer group currently pays relatively low rates, and this translates into a class rate of return that is far lower than the overall system average, an effort should be made to increase rates paid by those customers relative to other customers who currently pay higher rates and generate a higher rate of return. For example, KEDNY's SC-3 Multiple Family customers currently pay relatively low effective rates per therm, as shown on Schedule 3 of Exhibit ___ (URP-1), and these low rates have resulted in a very low class rate of return – negative 5.60% assuming the disputed costs are allocated using Design Day Demand, or negative 5.31% assuming the disputed costs are allocated using Winter Daily Demand.

Third, the largely across-the-board approach used by the Companies may not move far enough toward achieving more uniform rates of return. We agree that rate continuity is important, and agree that moderation is needed, to ensure no class experiences undue “rate shock.” This is particularly helpful in a situation where rates may be increased substantially, as the Companies have proposed here. However, experience suggests the final revenue requirement approved by the Commission may be substantially less than what was requested by the Companies. If this were to be the case here, then some greater degree of convergence might be appropriate for classes like KEDLI's SC-2A General Service Non-Heat (which currently generates a 13.71% return if the disputed costs are allocated using Design Day Demand and 9.98% if the disputed costs are allocated using Winter Daily Demand, compared to an overall system average return of 3.83%). There may be reasonable options which would achieve a somewhat greater degree of convergence without imposing extreme rate changes.

VI. RATE DESIGN

A. Background

Q. Before delving into the details of the Companies' rate design proposals and your response to those proposals, can you briefly introduce this topic and explain your general approach?

A. Yes. Although rate design is more of an art than a science, it is nevertheless a very important part of the overall regulatory process. It is often in this stage of the proceeding where the Commission's decisions will have the greatest short-run impact on customers, and the greatest long-run impact on the Commission's overall policy goals. We do not view rate design as an area where deference can appropriately be given to the utility's preferences, or where "business as usual" is an appropriate philosophy. The following discussion (in the context of electric rates) from page 5 of the Smart Rate Design for a Smart Future issued by the Regulatory Assistance Project in July 2015 is informative:

> Rate design is important because the structure of prices — that is, the form and periodicity of prices for the various services offered by a regulated company — has a profound impact on the choices made by customers,

> utilities, and other . . . market participants. The structure of rate designs and the prices set by these designs can either encourage or discourage usage at certain times of the day, for example, which in turn affects resource development and utilization choices. It can also affect the amount of electricity customers consume and their attention to conservation. These choices then have indirect consequences in terms of total costs and benefits to society, environmental and health impacts, and the overall economy.

In our view, some aspects of the Companies' current rate structure do not provide the right price signals to encourage energy efficiency and do not sufficiently incentivize customers to invest in more energy efficient products (such as higher efficiency water heaters and more efficient furnaces). We believe reasonable steps can be taken to improve this situation, strengthening the incentive for energy conservation and more effectively advancing the Commission's policy goals.

To advance the policy goals set forth in the 2015 New York State Energy Plan (system efficiency, carbon reductions, customer empowerment, and energy affordability) as well as the goals underlying the ongoing REV proceeding (Case 14-M-0101), we recommend that the Commission steer the Companies away from high customer charges (or minimum bills) and low tail block rates. Together with customer engagement technologies, this can better enable customers to take greater control over their utility bills, and more clearly and effectively reward them for investing in more insulation and energy-efficient appliances and heating systems, as well as making lifestyle adjustments that enable them to use energy more efficiently (e.g. using automated thermostats to adjust temperatures for maximum efficiency while maintaining comfort). We will discuss some of the weaknesses in the Companies' existing rates, and opportunities to advance the Commission's policy goals throughout the remainder of our testimony.

Before going into greater detail concerning specific opportunities and concerns applicable to these proceedings, it is worth noting that we understand the Commission faces a difficult task, and we realize the Commission must weigh the claims made by parties with widely varying perspectives. The Regulatory Assistance Project explained on page 8 of the July 2015 Smart Rate Design for a Smart Future paper:

> A variety of stakeholder interests are at play in the debate over rate design, and finding common ground is not easy. Regulators face the task of fairly balancing concerns among utilities, consumers and their advocates, industry interests, unregulated power plant owners, and societal interests. The regulator accepting the charge of “regulating in the public interest” considers all of these values.

For this reason, throughout our testimony we have endeavored to not focus only on short-term customer impacts – although we realize those impacts are of great importance to the interests of residential and small commercial customers whose interests UIU represents in these rate proceedings – but to also place our concerns into a broader context, which can help the Commission sort out competing claims from other parties and chart a course that makes significant progress toward achievement of the Commission's policy goals.

Q. Can you please elaborate?

A. Yes. We agree with the following statements found on page 73 in the Staff White Paper on Ratemaking and Utility Business Models issued July 28, 2015 in the REV proceeding:

> Rate design is the process of determining how a utility's revenue requirement will be recovered from customers. Rate design sends price and value signals that influence customer actions; the cumulative effect of many customer decisions ultimately affects the cost of the system. Rate design must try to prevent undue disproportionate or inequitable impacts on different customers within classes, and take into consideration policy objectives along with technical cost causation analysis. For those reasons, rate design requires a balancing among multiple objectives, principles, and interests.
>
> Traditionally, rate design has focused on the allocation of system costs to customers, assuming a uni-directional electric system designed around inelastic demand, with one-sided transactions between utilities and customers. While this approach has been effective historically, technological advances mean that the assumptions behind that approach no longer hold in their entirety.

Although written with a view toward electric utilities, these statements also have relevance to gas utilities, and the rate design issues we will be discussing in our testimony. Sufficient for the moment is to cite but one example: the goal of empowering customers to have greater control over their utility bills (a goal which tends to conflict with the past tendency in New York to accept proposals by utilities to keep increasing the fixed customer charge). Regardless of the motivations behind that past trend – which may have included the desire to recover fixed costs through fixed rates, ensure revenue stability for the utilities, or take advantage of inelastic demand by imposing rate increases on the rate elements that are perceived as having the lowest price elasticity – this trend was in direct conflict with the goal of empowering customers to exercise greater control over their utility bills, as well as the broader national goal of encouraging energy efficiency.

As the Commission stated on page 55 of the Order Adopting Regulatory Policy Framework and Implementation Plan in the REV proceeding, issued February 26, 2015, pertaining to customer engagement: "Staff notes that the majority of customers in New York currently lack the information, products, technologies, and incentives to fully participate in energy markets and take control of their monthly electricity bills." Overcoming those obstacles is a worthwhile goal that also has relevance to gas utilities.

Fortunately, the Companies seem to be taking some steps toward advancing this goal. Most notably, the Companies do not propose to increase many of their fixed customer charges (i.e., those portions of the utility bill that cannot be avoided no matter how much a customer conserves energy). We will discuss this aspect of the Companies' proposals in depth later in our testimony; for now it is sufficient to point out that whenever the Commission increases the fixed element of the bill and reduces the volumetric energy delivery rate (which can potentially be avoided by conserving energy), it reduces the customer's ability and incentive to control his or her monthly gas bill. As we will explain later in our testimony, customer charges are already at very high levels in New York, and any further increase in this rate element would tend to undermine one of the Commission's stated goals, as articulated in the REV proceeding.

We strongly believe that the public interest can best be advanced by heading in the opposite direction. While a slow and gradual process may be more appropriate than immediately implementing all of the changes that may ultimately be needed, there are benefits to at least beginning to move toward lower fixed charges and higher tail block rates. By decreasing the fixed part of the bill and increasing the variable part (the per-therm rate – particularly in the tail block), the Commission can provide a stronger incentive for customers to fully participate in energy markets, and a stronger incentive to learn about energy efficient products and technologies. Restructuring tariffs to move away from high customer charges and increasing the delivery rates is the first step to move towards a rate structure that better advances the goals of REV, more fully embraces New York State's long term energy efficiency policies, and advances the broad public interest.

B. Customer Charges and Volumetric Delivery Rates

Q. What have KEDLI and KEDNY proposed with respect to customer charges and volumetric gas rates for residential and small commercial customers?

A. As shown on Schedule 4 of Exhibit ___ (URP-1) and Exhibit ___ (URP-2), the Companies propose to keep many of the existing customer charges at the current level, while increasing the rest. Based upon our reading of the testimony of their Rate Design Panel and our review of their workpapers, it appears the proposed tail block rates were loosely based upon the results of their ECOS study (plus Site Investigation and Remediation ("SIR") costs), and the remaining block rates were adjusted to achieve recovery of the remainder of the revenue requirement. Accordingly, if this approach had been applied using ECOS studies that treated the disputed costs as demand-related, rather than customer-related, they would have proposed higher tail block rates.

Q. Can you briefly describe KEDLI's and KEDNY's current and proposed customer charges and volumetric rates for some of their firm gas customers?

A. Yes. As shown on Page 1 of Schedule 4 of Exhibit ___ (URP-1), for SC-1A Residential Non-Heat customers, KEDLI proposes to increase the customer charge or minimum bill (including the first 3 therms or less) from $17.66 to $19.75, which works out to an increase of approximately 12%. The next block (4 to 50 therms) would increase 28.7 cents per therm, and the final block would increase by 27.5 cents per therm, if the proposals are adopted. KEDNY proposes to increase the customer charge for this class from $13.74 to $16.25 (an increase of approximately 18%), while the second block (4 to 50 therms) would increase by approximately 48.4 cents for therm, and the final block would increase by 0.25 cents per therm, a shown on Schedule 4 of Exhibit ___ (URP-2).

For SC-1B Residential Heating customers, KEDLI proposes to keep the customer charge at $21.66, while the second block (4 to 50 therms) would increase by 15.9 cents, and the final block would increase by 22.5 cents. KEDNY proposes to leave the customer charge (including the first 3 therms or less) unchanged at $21.55. The next block (4 to 50 therms) would increase by approximately 24.8 cents per therm, and the final block would increase by 20 cents per therm.

As shown on Page 2 of Schedule 4 of Exhibit ___ (URP-1), KEDLI's SC-2A General Service Non-Heat and SC-2B General Service Heating customer charge would remain unchanged at $37.66. For both sets of customers, the second block currently has the same rate – $1.216 per therm for 4-90 therms – but this would change under the Company's proposals. This rate element would remain nearly unchanged for Non-Heat customers, while it would increase by approximately 33.9 cents per therm for Heating customers. For the next block, 91-3,000 therms, customers would face an increase of approximately 10.9 cents (non-heating) and 12 cents (heating) per therm, and the tail block rate (for more than 3,000 therms) would increase by approximately 16.5 cents per therm for Non-Heat customers and approximately 15.5 cents per therm for Heating customers.

KEDNY's SC-2-1 and SC-2-2 proposals are somewhat similar for its SC-2A and SC-2B customers, as shown on Page 2 of Schedule 4 of Exhibit ___ (URP-2). The customer charge would remain unchanged at $37.55 per month, while the tail block rates would increase to approximately $0.360 per therm (which includes a collapsing of the 90-3,000 therms and greater than 3,000 therms block rates for SC-2-2 non-heating customers).. This works out to an increase of 21 cents per therm for both groups of KEDNY customers. The other volumetric rates would increase by lesser amounts – for instance, approximately 16 cents per therm increase for the 91-3,000 therms SC-2-2 block rate and 6.4 cents per therm increase for the SC-2-1 rate for 4-90 therms and 13 cents per therm for the analogous rate for SC-2-2 customers.

Q. Do you agree with KEDLI's and KEDNY's customer charge and volumetric rate design proposals?

A. Not entirely. We agree with the Companies' decision to leave many of their customer charges unchanged. We also see merit to their decision to increase the tail block rates in some of the classes by a larger percentage amount than the other volumetric rates. However, we don't necessarily agree with the specific rate levels that have been proposed – particularly because the proposed rates reflect a revenue requirement that is probably higher than necessary, and also because of our disagreement concerning the interpretation and handling of "customer-related" costs. We disagree with some key aspects of the Companies' ECOS studies, but even if the ECOS results were to be taken at face value, they are only one factor to consider in designing rates. As noted earlier, rate design involves various tradeoffs – and simply tracking the results of one particular cost study does not provide a valid basis for resolving these tradeoffs – particularly when those results point in a direction that is contrary to important policy goals like encouraging energy efficiency and conservation.

Q. How do the Companies' customer charges compare to those in other jurisdictions?

A. In May 2015, the American Gas Association published a report that concluded that the nationwide median residential customer charge was just $11.25 per month, and the median rate for commercial customers was just $22 per month. As shown in the table below, the data in this report suggest the Companies (and other New York gas utilities) have some of the highest customer charges in the United Sates – the result of an upward trend that which may have had some appeal for New York utilities, as it helps maintain stable revenues, but which we believe conflicts with many of the Commission's policy goals (including ones set forth in REV order) as well as the broader goal of achieving just and reasonable rates that treat both small and large customers fairly.

Table 2
2015 Natural Gas Utility Median Monthly Customer Charges by Census Region

Census Region	Residential	Commercial
New England	$ 13.50	$ 28.41
Middle Atlantic	$ 14.60	$ 23.60
East North Central	$ 11.38	$ 24.00
West North Central	$ 13.16	$ 24.40
South Atlantic	$ 10.00	$ 22.00
East South Central	$ 14.00	$ 16.96
West South Central	$ 13.24	$ 18.51
Mountain	$ 10.80	$ 20.00
Pacific	$ 4.95	$ 14.90

Q. Gas utilities sometime argue that a fixed monthly fee is the correct way to recover costs that are fixed. How do you respond to this argument?

A. While we concede there is some intuitive appeal to this argument, it is more of a pricing tactic than a goal. Utilities sometimes advocate increasing fixed rates, or matching fixed rates to fixed costs, because it provides a more stable and predictable revenue stream. However, it does not advance the public interest, and it is not an appropriate policy goal. To the contrary; we believe it leads to prices that are inconsistent with the public interest. In particular, higher fixed rates make it harder for customers to control their monthly bills, they reduce the incentive for improving energy efficiency, and they shift more of the cost burden onto small customers, who gain less benefit from the system and should not be expected to contribute as much to these sorts of fixed costs as larger customers.

Q. Gas utilities also sometimes argue that customer charges should be increased, to be more closely aligned with cost. How do you respond to this argument?

A. We disagree for several reasons, including the fact that the relevant costs are lower than what is shown in the Companies' cost studies. Additionally, for the reasons discussed earlier, we do not think any portion of the cost of distribution mains (Account 367) should be treated as customer-related or recovered through customer charges. We also disagree with the assumption that the cost of services (the line that connects a customer to the distribution main) should be recovered as a flat monthly charge. While the cost of services (unlike the cost of distribution mains) varies directly with the number of buildings connected to the system, it does not necessarily vary with the number of customer accounts (especially in New York City, where a very high number of residential customers live in multi-unit buildings), nor is there any need to recover these costs through the customer charge or the initial block rate.

While we concede the investment in services is a fixed cost that doesn't vary from month to month, at the time it is engineered and placed into service, the investment does vary with the anticipated demand or the maximum volume of gas that is expected to be handled by the service during its economic life. The causation of this cost is therefore dependent in part on demand and energy. Furthermore, in many cases, a single service line will be used by all of the customers in a particular building – so the less capacity that is used by any one customer, the more capacity that will be available for use by the other customers in that building. In general, we think it is more logical and appropriate to analyze and recover the cost of services on a per-therm basis, rather than construing it as a customer cost.

Q. How do the Companies' customer charges compare to their customer costs?

A. Schedule 5 of Exhibit ___ (URP-1) compares KEDLI's customer charges to its customer costs, based upon the Company's ECOS study, excluding distribution mains and services. As shown, in some cases the customer costs are lower and in some cases they are higher than the current or proposed customer charges. For example, as shown on Page 1 of Schedule 5 of Exhibit ___ (URP-1), for SC-1A Residential Non-Heat customers, KEDLI's current customer charge of $17.65 and its proposed customer charge of $19.75 are both higher than the corresponding customer cost, which is just $15.70 per month. Similarly, as shown on Page 1 of Schedule 5 of Exhibit ___ (URP-2), KEDNY's current customer charge of $13.74 and its proposed customer charge of $16.25 for SC-1A Residential Non-Heat customers are both higher than its customer costs, which are just $11.08 per month.

A similar discrepancy exists for both of the Companies with respect to the SC-1B Residential Heat customers. For KEDLI, the current and proposed rate of $21.66 exceeds its monthly customer cost of $15.70, while for KEDNY the current and proposed rate of $21.55 exceeds its monthly customer cost of $15.46. On the other hand, for some classes, customer costs are less than the customer charges. For example, the current customer charge for KEDLI's SC-3A Multi Family Non-Heat and SC-3B Multi-Family Heat classes are $74.66 per month, while the customer costs are $90.81 and $109.22, respectively.

Q. What are your recommendations pertaining to customer charges and volumetric block rates for residential and small commercial customers?

A. We recommend the Commission not increase the Company's fixed monthly charges for most customers. Instead, the proposed revenue increase should be collected exclusively through increases in these customers' delivery volumetric rates. If the Commission concludes that the requested revenue requirement is overstated, and adopts a lower revenue requirement, it may be appropriate to moderately lower the fixed monthly charges in some cases, rather than maintaining them at their current level – at least in classes where the current customer charge exceeds the customer costs. It would also be appropriate to take some modest steps toward a block structure that declines less steeply, particularly for small commercial customers. In general, if the revenue requirement approved by the Commission is lower than initially requested, we believe the Companies' rate design for most classes can be improved by lowering the proposed initial and second block rates to a greater extent than any corresponding reduction to the proposed tail block rate.

By slowly transitioning rates in the direction we recommend, with less emphasis on the customer charge and initial block and greater emphasis on the tail block, the Commission can avoid rate shock and gradually move toward rates that better incentivize customers to conserve energy. This will be more consistent with other policies which are intended to encourage greater energy efficiency (e.g., outreach and customer education to encourage better weatherization; rebates for the installation of high efficiency heating systems), and will treat small commercial customers more equitably relative to larger commercial customers served on the same rate schedule.

Q. Do you have any other recommendations pertaining to gas customer charges and volumetric rates?

A. Yes. We recommend the Companies implement a detailed study to better understand residential and small commercial usage behavior, including the various factors that impact residential bills and customer reactions to those bills. The study should include a comprehensive review of the Companies' residential and small commercial gas load characteristics that can be used to develop alternative rate design structures. Although our proposal incorporates a modest redesign of the Companies' residential and small commercial rate structures, we recommend that the Companies implement a detailed study to assist in evaluating the end point of the transition – for instance, should all tail block rates be higher than early block rates, and by how much? The study should also evaluate various factors that impact customer usage and pricing, such as customer usage patterns, weatherization and installation of energy efficiency products, price elasticity, block rate differentials, housing stock, affordability, bill impacts (low income, median income, and all other customers), and weather sensitivities.

C. TC, IT, DG and EG Rates

Q. Would you please briefly explain how the Companies' TC, IT, DG and EG rates differ from their other rates?

A. In general, rates for TC, IT, DG and EG customers have not been analyzed and established in the same way as the rates paid by other customers. Because these customers generally have the option of using an alternative fuel (typically fuel oil), the Companies have been given considerable discretion to negotiate or establish “market-based” rates for these customers, subject to some general constraints established by the Commission. Consistent with the assumption of market-based rates, these classes have not necessarily been considered to be responsible for funding any particular share of the Company's overall revenue requirement. Instead, customers, who receive service under the firm sales and transportation tariffs have been responsible for meeting the Companies’ revenue requirement, and any revenues received from the TC, IT, DG and EG customers have been treated as an offset to that revenue requirement.

This ratemaking treatment, and proposed changes in this treatment, were not discussed in detail in the testimony of the Companies' Rate Design Panels. However, in response to a Request for Information from the City of New York (BULI-121), the Companies explained that “under the current rate design . . . TC customers are charged on a value-of-service basis. Under the proposed rate design, TC customer will be charged on a cost-of-service basis. The proposed volumetric rate for TC customers will be the SC-2-A tail block rate (applied to all therms delivered)."

The current approach, in which TC, IT, DG and EG rates are based upon value of service, the Companies are given discretion to take into account market forces, and the revenues from these customers are given special treatment; is not unique to these Companies. For example, Con Edison also provides service to these types of customers pursuant to separate riders, tariffs or contracts that give them pricing flexibility, and the resulting revenues are handled differently than regular firm sales or transportation service.

The general theory behind Temperature Controlled service is that the customers will switch to an alternative fuel source during very cold weather, which frees up capacity on the distribution system during cold snaps, thereby ensuring that ample capacity remains available for the benefit of customers who lack dual-fuel capability. A somewhat similar theory applies to IT rates, and to some degree DG and EG rates – these customers are charged a lower rate for gas delivery service, but they can be interrupted (forced to switch to an alternative fuel or shut down their operations) during peak load periods.

Q. From the perspective of economic theory, are there benefits to having some customers install dual-fuel capability, or are otherwise be willing to have their service interrupted?

A. Yes. Just as there are economic benefits when a utility system serves a diverse mix of customers with loads that peak at different times, there are benefits to serving both firm and interruptible customers on the same system. By turning some customers off-line during peak periods, capacity is freed up for the use of other customers. In general, when some customers can be interrupted or curtailed during times when the system is congested, it becomes feasible to use a limited amount of system capacity to serve more firm customers, or it becomes feasible to provide a given set of firm customers with reliable service using a smaller, less expensive system.

Interruptible and temperature-controlled service have the potential to be a win-win arrangement for everyone – the non-firm customers benefit from lower rates, and firm customers benefit from having more capacity available to serve their needs during peak periods – thereby keeping system costs and customer bills lower they would be if everyone received firm service. The extent to which this arrangement benefits firm customers depends upon how congested the system is (i.e., how close the firm load comes to exceeding available system capacity), how costly it would be to increase capacity to relieve the congestion, and the amount of revenue contributed by the non-firm customers (i.e., how much firm rates are reduced due to the arrangement).

The extent to which this arrangement benefits non-firm customers primarily depends on the magnitude of the discount they receive, relative to the firm rate they would otherwise pay (assuming they would qualify for firm service), or the magnitude of the savings they achieve by using non-firm gas service rather than an alternative fuel, net of the additional costs they incur in order to qualify for the rate (e.g. maintain dual fuel capability, or periodically shut down operations during peak periods).

Q. To your knowledge, has the Commission endorsed the viewpoint that firm customers should benefit from non-firm customers using the gas distribution system?

A. Yes. We are not aware of any recent cases in which the Commission has opined on the optimal pricing of temperature-controlled, curtailable and interruptible service. However, the Commission has recognized that firm customers should receive the bulk of the financial benefit when non-firm customers use that system, thereby helping to offset some of the cost burden. For instance, in a 1995 decision involving Long Island Lighting Company, the Commission agreed that a pricing proposal designed to "maximize interruptible revenue margins for the benefit of core firm service customers, is consistent with established policy and practice and with the Commission's Opinion No. 94-26 in the gas restructuring proceeding." (Case 94-G-0786, Recommendation of Department of Public Service dated April 27, 1995, Approved as Recommended May 12, 1995, at p. 9.)

Opinion No. 94-26, among other things, established the principle that interruptible transportation service is considered to be a "Non-Core Market" service. (Case 93-G-0932, Opinion No. 94-26 (issued December 20, 1994) at p. 16.) That decision also placed some limits on the gas distribution utilities' pricing discretion with respect to maximizing revenues from Non-Core Market services. In particular, the Commission decided to "leave unchanged the prevalent policy of setting the upper limit for the price of market-priced non-core service equal to the rate (or net-of-gas margin) for the core service that would otherwise be taken." Id. at p. 26.

Q. What do KEDLI and KEDNY propose with regard to TC, IT, and DG rates?

A. The Companies decided to develop their TC, IT and DG rates on a cost-of-service basis, rather than a value-of-service basis. Hence, they included these customers in their ECOS studies, and they are proposing to increase rates for these customers by a lesser percentage than other customers, based upon the ECOS studies results.

Q. What do KEDLI and KEDNY propose with regard to Electric Generator rates?

A. The Companies did not discuss large Electric Generators in detail in their direct testimony. However, it appears that the Companies charge this group of customers much lower rates than they are charging other non-firm customers, and they do not propose to increase their rates. Additionally, the Companies have chosen not to include this group of customers in their ECOS studies.

According to the information included in responses to Information Requests (included in Exhibit __ (URP-3)), Electric Generators received delivery of more than 400,000,000 therms through the KEDNY system during the test year, and they are forecast to receive delivery of a similar volume during the rate year. However, they pay very little for this service – revenues from this group of large customers was less than $10 million during the test year, and revenues are forecast to decline to less than $9 million during the rate year. In both years this information indicates the EG customers are paying less than 3 cents for each therm delivered to them. In total, this small group of large customers receives more than half the total volume of gas delivered through KEDNY's system, yet they contribute less than 2% of KEDNY's revenues.

The Companies' testimony did not include a detailed justification for this discrepancy, nor have they provided any evidence that these customers would be unable or unwilling to pay more for gas delivery service if the Commission were to require them to do so. When asked whether they had performed any studies of the price elasticity of demand for interruptible services, KEDNY responded that it had not. When asked by the Long Island Power Authority in Information Request No. LIPA-1 for detailed support for various components of the EG rates, KEDLI responded by referring to Case 98-G-0122, which established certain pricing principles and policies applicable to the pricing of gas transportation for electric generation. The Commission's Order in that case, issued March 17, 1999, established rates of less than 3 cents per therm for gas transportation service by local gas distribution utilities.

Q. What is your response to the Companies' proposed handling of TC, IT, DG and EG rates?

A. We do not believe the Companies' ECOS study results provide meaningful information concerning the appropriate prices to charge these customers. The Companies' ECOS study results are largely driven by the allocation of costs in proportion to design day peak usage. Since these types of customers are assumed to be off-line during the design day, they are assigned little or none of the costs of the transmission and distribution lines that form the backbone of the system – yet these customers benefit greatly from these lines, and their loads can represent a substantial share of total demand on the system during many other days of the year.

As the assigned share of investment in transmission and distribution mains approaches zero, the rate base allocated to these classes will be very small, and the calculated rate of return will tend to be correspondingly large. However, the resulting percentage rates of return do not provide an accurate indication of how reasonable their prices are relative to those paid by firm customers (who are assigned the full burden of mains that are used by both firm and interruptible customers).

This problem is alleviated somewhat when the disputed portion of the cost of the distribution mains is assigned based upon winter daily demand. The rates of return computed using this methodology are not as high – although they still exceed the system average in every case, as shown on Page 3 of Schedule 2 of Exhibit ___ (URP-1) and Exhibit ___ (URP-2). These Exhibits also show what happens if 100% of the costs in Accounts 367 are classified as "demand-related" but the "minimum system" portion is allocated using Winter Daily Demand, while the remainder is allocated using the Companies' Design Day Demand allocator.

Nevertheless, regardless of the allocation methodology chosen, the resulting percentage rates of return do not provide a meaningful indication of how the cost of interruptible gas service compares to the cost of using fuel oil or some other fuel, and thus the ECOS study results do not provide any useful guidance concerning how high the interruptible rates can go before the IT, TC DG and EG customers will find it economically beneficial to switch to another fuel source. In general, we question whether it makes sense to begin setting rates for interruptible service on a cost-of-service basis, especially since most cost calculations are highly dependent upon peak-demand based allocation factors, and these classes will often have (or be assumed to have) little or no usage during the peak.

Q. What do you recommend concerning TC, IT, DG and EG rates?

A. Considering the unique characteristics of interruptible and temperature-controlled service, we believe it is reasonable to continue to use value-of-service as the primary basis for setting these rates. We also believe it is appropriate to continue to offer these customers a discount relative to the rate they would pay if they were to receive firm service. We have seen no evidence that indicates the existing discounts are too small, or need to be significantly increased – either to ensure these customers are treated fairly, or to discourage them from switching to an alternative fuel.

Since two of the main criteria for setting interruptible rates are to ensure that a reasonable discount is offered for non-firm service relative to the analogous rates charged for firm service, and ensuring that a reasonable contribution is provided by non-firm customers for the benefit of firm customers, it would be logical and reasonable to increase the rates charged non-firm customers at the same time that rates are being increased for firm customers.

To the extent any party claims that non-firm customers' rates should increase by a lesser percentage than other customers, such a claim cannot rest solely on an ECOS study. The ECOS results are of limited value or relevance in the context of interruptible customers, as so few costs are allocated to them under standard allocation methodologies.

In sum, we recommend the Commission consider increasing non-firm rates to a moderate extent, while maintaining a reasonable discount relative to firm service, with the precise percentage increase depending upon the revenue requirement ultimately approved.

Q. Does this conclude your direct testimony, which was prefiled with the Commission on May 20, 2016?

A. Yes.