STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service.	Case 16-E-0060
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service.	Case 16-G-0061
Proceeding on the Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service.	Case 15-E-0050
Tariff filing by Consolidated Edison Company of New York, Inc. to revise General Rule 20 Standby Service contained in its electric tariff schedules, P.S.C. Nos. 10 and 12.	Case 16-E-0196

DIRECT TESTIMONY

OF

UIU GAS RATE PANEL ON THE JOINT PROPOSAL

Dated: October 13, 2016
Albany, New York

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I. INTRODUCTION AND OVERVIEW

Q. Would the Panel please state their names and business addresses?

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.

(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 Company of New York, Inc. ("Con Edison" or "the Company") 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. 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 16-G-0257, 16-G-0058, 16-G-0059, 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 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, Cases 15-E-0285 and 15-G-0286 involving Rochester Gas and Electric Corporation and in Cases 16-G-0058 and 16-G-0059 involving Keyspan Gas East Corporation d/b/a National Grid ("KEDLI") and Brooklyn Union Gas Company d/b/a National Grid ("KEDNY"), and Case 16-G-0257 involving National Fuel Gas. I also submitted prefiled direct and rebuttal testimony as part of the UIU Gas Rate Panel in this proceeding, Cases 16-G-0060, *et. al*.

(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, 15-G-0286, 16-G-0257, 16-G-0058 and 16-G-0059. I also submitted prefiled direct and rebuttal testimony as part of the UIU Gas Rate Panel in this proceeding, Cases 16-G-0060, *et. al*.

Q. What is the nature of this testimony?

A. We will focus on some key aspects of the tariff changes contained in the Joint Proposal filed in these proceedings on September 20, 2016 ("JP"). Although we reserve the right to respond to testimony filed by other parties concerning other topics, our direct testimony is primarily focused on those portions of the JP that adopt the Company's gas embedded cost of service ("ECOS") study, its gas marginal cost of service (“MCOS”) study, and certain aspects of the Company’s gas 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 Company's current and proposed gas rates, particularly with respect to the JP’s proposed allocation of an excessive share of the revenue burden to small commercial and residential gas customers, the balance between fixed monthly rate elements (gas customer charges) and delivery volumetric rates, and the rates charged for non-firm gas customers.

Q. How is your testimony organized?

A. Our testimony has six 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 Company's previous gas rate case, which was initiated in January 2013 and resolved by a Multi-Year Rate Plan in February 2014 (hereinafter “prior rate case”).

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 Company’s gas 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 JP's proposed revenue allocation. In the sixth section we discuss the Company's current rate design for gas residential and small commercial customers, and we examine key aspects of the Company's 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 JP's proposed 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 this section we also discuss the rates charged for non-firm gas service.

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

A. Yes, Exhibit __ (UGRP-JP-1) accompanied our original prefiled direct testimony; it continues to be useful and relevant in the context of the proposed JP. In addition, we prepared 9 exhibits to illustrate some of our concerns regarding the JP.

Q. Would you please describe these Exhibits?

A. Yes. Exhibit __ (UGRP-JP-1) contains five schedules pertaining to Con Edison'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 gas ECOS study submitted by Con Edison, 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 ___ (UGRP-JP-2), Exhibit ___ (UGRP-JP-3), and Exhibit ___ (UGRP-JP-4) compare the JP revenue allocation in Rate Years 1, 2 and 3, respectively to a similar revenue allocation except it assumes Account 376 is allocated using One Hour Peak NCP Demand and the portion of the revenue requirement attributable to Advanced Metering Infrastructure (AMI) is allocated using therms. In each of these 3 exhibits, Schedule 1 provides a summary comparison of the revenue allocations and resulting percentage rate changes for various customer classes. Schedule 2 illustrates the difference in revenue allocation flowed through to rates if the provisions of the JP are adopted and our revenue allocation and rate design recommendations are adopted by the

Commission. Finally, Schedules 3 – 5 provide similar comparisons in the context of typical bills – showing the amount that would be paid each month by typical customers – thereby providing further insight into the impact of the revenue allocation and related rate design provisions of the JP in comparison with our recommendations.

Exhibit ___ (UGRP-JP-5) through Exhibit ___ (UGRP-JP-7) are very similar, including the same sequence of schedules, except that it uses an ECOS study in which Design Day Peak demand is used to allocate Account 376. Finally, Exhibit ___ (UGRP-JP-8) through Exhibit ___ (UGRP-JP-10) include a similar set of schedules, which compares the JP revenue allocation to an Across the Board approach to revenue allocations.

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:

<u>Gas Cost of Service</u>

We recommend the Commission reject the JP's proposed method of allocating the costs of gas distribution mains in its gas ECOS study. The method proposed by the Company and adopted in the JP tends to allocate an excessive share of certain disputed costs onto small usage customers in the commercial and residential service classes. Instead of accepting the approach proposed by the Company, 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. Both alternatives analyze the disputed costs by allocating distribution mains based upon demand, which is an approach which has previously been accepted by the Commission and Department of Public Service ("DPS") Staff in other New York State proceedings, and has been accepted in other states. The first alternative uses 1 Hour Non-Coincident Peak Demand, while the second uses Design Day Demand.

Gas Revenue Allocation

There is no need to drastically adjust the existing revenue relationships based on the Company's gas ECOS results, as proposed in the JP, since the differences in class returns are relatively modest, and are entirely dependent upon aspects of the study which we believe are invalid and should be rejected. However, our gas ECOS results show very substantial discrepancies in the degree to which certain customer classes are contributing their fair share of the system costs, and it is reasonable and appropriate to take that information into account when setting rates. Exhibit ___ (UGRP-JP-2) through Exhibit ___ (UGRP-JP-7) illustrate the effect of using the JP's approach revenue allocation with the results our two ECOS studies. The JP signatories propose to shift more of the revenue burden onto SC-1 (Residential & Religious Non-Heat), but this class already has a rate of return that is significantly higher than the system average under both of our ECOS studies.

While we firmly believe these ECOS studies are superior to the one used in the JP, we recognize that an ECOS study is merely a tool that should constitute only one part of the overall ratemaking process. Where the discrepancies are small, or entirely dependent upon aspects of the ECOS methodology which are unreliable or disputed (as with the Company's gas ECOS results) it is reasonable to use more of an across-the-board approach to distributing the revenue burden, giving reduced weight to the gas ECOS results. Accordingly, for comparison purposes, in Exhibit ___ (UGRP-JP-8) through Exhibit ___ (UGRP-JP-10) we illustrate an across-the-board approach that does not adjust the revenue allocation for the surplus or deficiencies shown in the ECOS results.

Given the magnitude of the revenue requirement and overall rate changes reflected in the JP, we believe it is feasible to modify the allocation of revenues to the various classes to move into closer alignment with our gas 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, and how much weight is given to the results. For illustrative purposes, all of our Exhibits use the same approach adopted in the JP with respect to how the ECOS results are reflected in the revenue requirement – we've adjusted the revenue requirement to eliminate 100% of the surplus and deficiency in each class by the end of Rate Year 3. To be clear, however, in our view there is no need to adjust the existing revenue relationships this rapidly. A slower, more gradual approach would be reasonable, if the Commission wants to give less weight to the ECOS results, or if it wants to adjust the rate relationships more gradually. Finally, we want to make clear that any such realignment process should not be based upon a gas ECOS methodology that places an excessive and unwarranted burden on residential and small commercial customers, like the one used in the JP.

Gas Rate Design

Gas Customer Charges and Volumetric Rates

We agree with the JP's proposal to hold constant customer charges for gas Service Class ("SC") SC-2 General Service I (Non-Heat), SC-2 General Service II (Heat), and SC-3 Residential and Religious – Heat customers. However, we have concerns about the Company' proposals to increase customer charges for SC-1 Residential and Religion (non-heating) gas customers. Instead, we recommend that customer charges not be increased for that class, and depending on the share of the final revenue requirement that is allocated to each class, it may be appropriate to make a small downward adjustment to customer charges in situations where the customer charges currently exceed customer costs. This would improve fairness and send 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 Company implement a detailed study to better understand usage characteristics and behavior which can be used to evaluate alternative gas rate design structures.

Non-Firm Gas Rates

We believe it is reasonable to continue to use value-of-service as the primary basis for setting non-firm gas 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. However, the Company has presented no evidence that indicates the existing discounts are too small, or need to be increased – either to ensure these customers are treated fairly, or to discourage them from switching to an alternative fuel. To the contrary, there are indications that some of the existing non-firm rates are rather low, compared to the rates paid by firm customers.

Because two of the main criteria for setting non-firm 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 to non-firm customers at the same time that rates are being increased for firm customers. However, the JP signatories' decided to keep the rerates for SC12 Rate II far below the level paid by the corresponding firm service classes, and far less than the value of service those customers receive. While small commercial customers receiving firm service are paying 40 to 70 cents per therm, these large non-firm customers are paying less than 9 cents per therm. Instead of reducing this enormous gap, the JP actual widens the discrepancy by largely sheltering these non-firm customers from sharing in the burden of the proposed rate increase. The SC12 Rate II customers would not experience any rate increase during Rate Year 1, and in Rate Years 2 and 3, their rate will increase by fraction of a cent per therm – far less than the increase required of firm customers.

The Company did not include non-firm customers in its gas ECOS study, and we agree with this decision, since so few costs would be allocated to these customers under standard allocation methodologies. Instead, we recommend the Commission increase the non-firm rates based upon fairness and value-of-service considerations, while maintaining a reasonable discount relative to firm service. We recommend the Commission reject this portion of the JP, and instead require the SC12 Rate II customers to bear a more reasonable share of the revenue burden – one that is more consistent with the value of the service these customers receive.

III. BACKGROUND

Q. Please briefly summarize the outcome of the Company's previous rate proceedings, initiated in 2013.

A. In its Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, issued and effective February 21, 2014 in Cases 13-E-0030 et. al., the

Commission decreased gas revenues for Con Edison during the initial year of a three-year rate plan, then increased rates during each of the subsequent two years, resulting in no change in Con Edison's rates on a levelized basis. The Order thereby established a multi-year rate plan that ensured stable base delivery rates for all major categories of customers for at least three years.

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

A. Yes. The JP would establish a three-year rate plan, authorizing Con Edison to collect $35.5, $92.3, and $89.5 in additional revenues from customers per respective rate year. This corresponds to annual rate increase of 3.1%, 7.5%, and 6.7%.

If approved, the requested rate changes will impact approximately 1.1 million Con Edison gas customers, of which approximately 666,000 (61%) are residential accounts that use gas for purposes other than heating (SC-1), and approximately 298,000 (27%) are residential accounts that use gas for heating (SC-3). The majority of the remaining accounts are small commercial customers in SC-2, although the Company also serves a variety of other customers, including government accounts, larger commercial and industrial customers in SC-2 and SC-12, 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 Con Edison system.

The JP would raise non-firm rates considerably less than firm rates and it would exacerbate existing rate disparities by shifting more of the revenue burden onto small customers relative to large customers. Since the revenue allocation and rate design proposals in the JP are at least partly driven by some key decisions the Company made in developing its gas ECOS study (and, to a much lesser extent, its gas MCOS study), we will discuss the costing issues first, before turning to the remaining issues.

IV. GAS 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 Con Edison's gas ECOS study, which the JP adopts in full?

A. Yes. The Company's gas ECOS study provides the underlying foundation for the JP's proposed gas revenue allocation (distributing the revenue requirements among different customer classes) and some key aspects of its gas rate design proposals. The gas ECOS study was 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 compression equipment used to liquefy and store gas was allocated to different classes based upon their respective levels of design day usage.

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 the impacts of disputed judgments made during the second step tend to show up during the final step, and because a variety of different peak allocation factors can be chosen to allocate demand-related costs.

For example, most analysts agree on the function of equipment used to liquefy and compress gas – during the functionalization step this equipment is placed into the functional category of “storage.” However, analysts may disagree concerning how the cost of that equipment should be allocated. For example, Con Edison proposes to allocate the cost based upon design day demand – essentially, the demand placed on the system by each class during an extremely cold winter day – while KEDNY allocates the analogous equipment based upon winter throughput – essentially the demand placed on the system by each class during an average winter day. Needless to say, this difference in allocation method cannot be explained by differences in the function performed by this type of equipment in their respective systems – or by differences in how cold it gets in Brooklyn compared to the other boroughs.

One aspect of the classification and allocation process that is particularly controversial in this case was the Company's 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 Company's approach is apparently founded on its understanding of the concept of "customer-related" costs:

> During the process of functionalization, all costs are classified as demand-related, commodity-related, or customer-related. Demand-related costs are fixed costs created by the on-peak hourly loads placed on the various components of the gas system. Commodity-related costs are variable costs caused by the total quantities of gas delivered during the year. Customer-related costs are fixed costs caused by the presence of customers connected to the system, regardless of any customer's particular level of usage.
>
> (Direct pre-filed Testimony of Con Edison Gas Rate Panel, pp. 12-13.)

The Company's Gas Rate Panel asserts that it classified as customer-related those fixed costs which are "caused by the presence of customers connected to the system;" however, this category was not, in fact, limited to costs that are caused by the presence of customers. To the contrary, the Company actually took fixed costs which they decided not to classify as "demand-related" and instead classified them as "customer-related." In other words, the Company did not limit the "customer-related" classification to costs that are exclusively and unambiguously caused by the presence or absence of specific customers.

In some aggregate sense, of course, the presence of customers is critically important – very few costs would be incurred if there were no customers present on a gas system, since there would be no revenues available to recover the costs. Without at least one customer, the system would never be built in the first place, and it would not remain in operation. From an economic perspective, the distribution system has one primary purpose: delivering energy to customers. To receive this energy, customers need to be connected to the system. But the presence of any particular customer, or even an entire class of customers, will have very little impact on the design or operation of the system, absent other correlated factors, like the need to deliver gas to particular locations at particular times.

A gas 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 at the city gate. The entire system is designed to efficiently move gas from its source to the location where it will be burned, i.e., customers' premises. However, the presence or absence of any given customer will have little or no impact on the design or operation of the system.

One can certainly argue that some costs are customer-related to a greater degree than other costs. For instance, certain components of the system are physically located at, or in very close proximity to, the customer's premises. But this does not mean that those components are purely customer-related, or that other factors aren’t involved in determining the magnitude of the costs incurred in installing and operating those components. Consider first the extreme case of gas meters that are located at the customers' premises. Needless to say, the number of meters is very highly correlated with the number of customers, and no one disputes that meter costs are customer-related, at least in part, or that it is reasonable to recover the cost of reading meters on a per-customer basis. But in a very fundamental sense, 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 necessary for those customers that use large volumes of gas during peak periods.

This sort of complexity applies to an even greater extent as we move farther away from the customer toward the source of gas. Consider the example of service lines that connect multi-tenant office buildings and apartment buildings to the distribution main that goes along the street. In most cases, the service line will be designed and installed based upon a projection of the maximum amount of gas that is anticipated to be used by future occupants of the building (peak demand for gas going into the building, taking into consideration diversity of the various uses within the building). The calculations will consider the overall size of the building, and (in the case of an apartment building) the mix of one-, two- and three-bedroom apartments. However, variations in the number of individual customers in the building will have little or no impact on the cost of the service line that is needed to meet a given level of demand for gas in the building. In fact, even if all the gas were sold to a single customer (e.g. the landlord), the cost of the service line would be the same as if there were dozens or hundreds of individual customers having the same aggregate demand for gas.

There is an inherent arbitrariness in trying to force costs into a simplistic three-part classification schema (energy-, demand-, and customer-related) since costs are actually incurred as part of a complex, multi-dimensional process that involves more than just three causative factors. In this case we are particularly troubled by the arbitrary results of Con Edison's approach to certain disputed costs that it proposes to classify as "customer-related." While the dispute in this case is focused on the arbitrary classification of certain costs as "customer-related" the underlying problem is not unique to "customer-related" costs; it could just as easily arise in another context. For example, consider what would happen if the revenue allocation and rate design process were founded on a cost study in which one of the key steps involved classifying all costs as either safety-related, or not 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 Company chose to classify a large fraction of delivery costs as "customer-related." It consequently proposes to allocate most of these costs to classes with the largest number of customer accounts, and this led it to design rates that place a greater burden on smaller customers relative to larger customers. This approach effectively treats a large portion of the costs of the distribution mains as “fixed” costs to be allocated and recovered on a relatively uniform per-customer basis, and assumes that only the remaining, “variable” portion of the cost of mains should 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 Company's treatment of these costs in its gas ECOS study, 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 <u>not</u> 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 Company's cost study, would you please briefly discuss Con Edison's MCOS study?

A. Yes. The Company submitted a MCOS study, which indicates that the long run marginal cost of delivering gas is approximately 43 cents per therm. However, the Company and the JP placed very limited reliance on the results of this study – it was primarily used to decide on the discount offered to customers receiving service under Rider D – Excelsior Jobs Program. Many of the key numbers uses in the MCOS study were taken from ECOS study, and thus some of our concerns regarding the ECOS study also apply to the MCOS study. However, given the limited role the MCOS study plays in the Company's filing, our comments concerning marginal costs will be brief, and primarily conceptual.

2. <u>Embedded versus Marginal Costs</u>

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. Each 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. <u>Fully Allocated Embedded Costs</u>

Q. Please elaborate on the purpose of fully allocated ECOS studies, and explain some of its limitations.

A. Fully allocated ECOS 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 study (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 Company's ECOS study and corresponding gas rate proposals included in the JP?

A. Yes. We strongly disagree with the manner in which certain allegedly "customer-related" costs are being handled in the Company's gas ECOS study and in the JP's rate proposals. We believe these proposals do not follow sound principles of cost-causation. As a result, too much of the joint and common cost burden would be placed on small residential and commercial customers, the proposed rates are not consistent with the manner in which these types of costs would typically be recovered in competitive, unregulated markets, and the proposed rates 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 Company's gas ECOS study?

A. Yes. We disagree with the proposed treatment of Account 376: Distribution Gas Mains. Con Edison proposes to classify approximately 54% of these costs as "demand" related and approximately 46% as "customer" related. This leads it to allocate 46% of this important category of costs largely in proportion to the number of customers in each service classification. The classification and allocation of FERC Account 376 determines the disposition of more than half the Company's gas rate base (and related aspects of the JP's proposed revenue allocation and rate design) so this treatment is highly significant.

Q. Has the Company explained why it proposes to classify and allocate these gas costs in this manner?

A. Not in detail. As mentioned earlier, Con Edison's Gas Rate Panel apparently believes a portion of the distribution gas mains are fixed costs caused by the presence of customers connected to the system, regardless of any customer's particular level of usage. The explanatory notes accompanying its ECOS study explain the treatment of Account 376 as follows: “This account was functionalized to the Distribution-Demand (“Demand Component”) and Distribution-Customer (“Customer Component”) functions based on the development of the Minimum System for Gas Mains.” (Exhibit ___ GRP-1, Schedule 1, page 19).

The share of Account 376 that was categorized as customer-related (46%) was derived from an analysis of the embedded cost of steel, cast iron and plastic mains of various sizes. For example, the Company selected 2.00 inch steel mains as the smallest “predominant size” and compared the cost of these mains to the cost of all steel mains (including smaller and larger ones). Similarly, it selected 4.00 inch cast iron mains as the “predominant size” and compared their cost to the cost of all cast iron mains. Finally, it selected 1.25 inch plastic mains as the “predominant size” and compared their cost to the cost of all plastic mains. While the Company's testimony doesn't include an explanation of the mechanics of its calculations, or the underlying logic it used these calculations to estimate the portion of Distribution Gas Mains in Account 376 it believes should be allocated in proportion to the number of customers in each class, with the remainder being allocated in proportion to 1 Hour Non Coincident Peak Demand.

Q. Is this a highly precise or scientific “minimum system” analysis?

A. No. Putting aside for a moment our fundamental disagreements with the “minimum system” approach in the first place, it is worth noting that the Company's calculations are highly arbitrary and its methodology is inherently unreliable. The

Company’s approach is not in any way tied to an analysis of the number of customers served by the system, nor is it based upon a “clean slate” engineering analysis of what it would cost to build a “minimum size” system under today's conditions.

The Company's methodology is tied to embedded cost data for different size mains, but those data are influenced by many extraneous factors that are not adequately “held constant” in the Company's analysis, including the location where the gas main was installed and the difficulties that were encountered along its installation route. These non-size related factors can be significant, which may help explain some of the anomalies in the data used by the Company. For instance, 1.5 inch and 2.5 inch steel mains both show lower costs per foot than 2.0 inch steel mains, which is the size used in the Company's minimum system analysis. (Work papers for Exhibit ___ (GRP-1) Schedule 1 - Revised.xls, Tab TRB, Rows 561-661). In some cases, these sorts of cost discrepancies might be attributable to weak data, but not in all cases. For instance, the data set includes cost information for more than a million feet of 2.00 inch plastic main, which cost of $107 per linear foot, installed (Id., Row 645). However, the Company chose to instead focus on 1.25 inch plastic mains, which cost $148 per linear foot. (Id., Row 643). By choosing the more costly size, the Company shifted more costs into the “customer-related” category. To appreciate how sensitive the minimum system analysis on distribution main costs is to the methodology used by the Company, consider what would have happened if it had focused on 1.50 inch steel mains and 2.00 inch plastic mains, rather than 2.00 inch steel mains and 1.25 inch plastic mains: with just these two minor changes, it could have developed a “customer-related” share of 18%, rather than 46%.

Q. Putting aside the specific calculations, can you explain why you fundamentally disagree with classifying these disputed costs as "customer-related" and why you believe the distribution gas main costs in Account 376 should not be allocated or recovered 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, that 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 "minimum system" calculations may 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 approach has been used by utilities and regulators in other states, and 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 Gas 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) (and this was subsequently accepted by the Commission), as well as in some past gas cases involving KEDNY and KEDLI (06-M-0875, 06-G-1185, and 06-G-1186). Similarly, New York State Electric and Gas ("NYSEG") and Rochester Gas and Electric ("RG&E") classified 100% of Distribution Gas Mains in Account 376 as demand-related in several different gas 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 gas 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 (since it is more costly to deliver a given volume of gas during peak periods, when many different customers all need a lot of 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 ignore the vast differences in benefits received by customers of different sizes, 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 Company's "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 are 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. Instead, 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.

Were it more accurately developed, a "minimum system" approach would essentially focus on the distinction 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, to estimate the smallest level of fixed cost that could potentially be incurred to serve a given geographic area, without considering any of the costs that vary depending upon demand. 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, the variable portion of the cost will mostly vary with the peak volume of energy that is expected to flow through the facilities, and the fixed portion of the cost will mostly vary with the number of miles of streets along which service will be provided. The key point is that the investment in mains does <u>not</u> vary in proportion to the number of customers along the streets where the gas mains are (or will be) installed.

To the extent the costs in Account 376 vary in relation to 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 gas 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 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 curtailable 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 (i.e., they help "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 Company has relied on 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 attributable to the smallest "predominant size" main should be classified and allocated on the basis of the number of customers in each class.

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 influence 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 the 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 causes 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 gas 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 his or her 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.

Uniform Per-Customer Fixed Cost Recovery is Inequitable

Q. Are you saying that the JP will result in an inequitable allocation and recovery of gas costs?

A. Yes. The JP gives far too much weight to the Company's flawed Minimum System approach to the classification, allocation and recovery of the cost of distribution gas mains. This methodology effectively causes a large fraction of these costs to be recovered on a uniform per-customer basis. In turn, if this aspect of the JP were accepted by the Commission, it would place an excessive and undue burden on individual residential and small commercial customers. This burden would be unjust and inequitable, as well as being inconsistent with the manner in which these types of costs are typically recovered in most unregulated markets (as discussed in our direct testimony). By comparison, recovering the cost of distribution gas mains through volumetric rates is a reasonable methodology that does not place an excessive share of the fixed costs on any particular class or category of customers.

Q. Can you please explain why you believe a relatively uniform per-customer approach is inequitable?

A. Yes. To understand the problem with the type of cost recovery that is proposed in the JP, consider a simple hypothetical example, focusing on a small business owner who operates a 1,000 square foot retail store. In this example, the small retailer competes with several other retailers, including a 50,000 square foot department store down the street. The larger store enjoys many advantages, including a famous name brand and a large advertising budget. But the small retailer also enjoys some competitive advantages, including a more personalized service and a more interesting, less commonly seen selection of merchandise, focused on its particular area of specialization.

In this example, the department store uses about 50 times more natural gas to heat its store (compared to the small retailer), but its peak demand is only 40 times as large. This translates into a moderate cost advantage for the department store, when comparisons are made on an apples-to-apples, per-square foot basis – a pattern that applies to most of the items included in their respective utility bills. This would also hold true for the cost of distribution gas mains if they are allocated using the demand-based ECOS methodology – the department store is allocated a larger share of the distribution gas mains, in proportion to its larger peak demand, which works out to net 20% cost savings on a per-square foot basis.

In contrast, under the uniform per-customer method proposed by Con Edison and accepted by the Staff Gas Panel in this case, the department store would be allocated the same dollar share of the fixed Minimum System costs as its much small competitor, despite using 50 times more energy and having a peak demand that is 40 times larger. If the uniform per-customer cost recovery approach were to be accepted by the Commission and flowed through to bills, both stores would end up contributing the same exact dollar amount per month toward the Minimum System portion of the Company's gas costs. This would clearly be inequitable, since one store is 50 times larger than the other, and it receives 50 times as much natural gas from the system. The inequitable nature of this cost allocation and recovery methodology becomes even clearer when their respective shares of these fixed infrastructure costs are compared on an apples-to-apples basis: the department store would pay 98% less per square foot than its smaller competitor.

It is fundamentally inequitable to expect the smaller store to contribute the same amount (in dollars) as its much larger competitor, merely because each store represents a single customer account on the utility's gas system, while ignoring the vast difference in size and the extent to which they use the system. Considering that we are dealing with fixed overhead costs of the system that cannot be directly attributed to, and are not caused by, either store, this extreme disparity in cost burden is clearly inequitable.

To consider a similar analogy, it is hard to imagine anyone arguing that the smaller store (or its landlord) should pay the same dollar amount of property taxes as the department store. The fact that the smaller retailer would be required to pay 50 times more per square foot than its larger competitor would surely dissuade the taxing authorities from accepting the argument. In reality, of course, the tax burden is spread much more equitably, because virtually all local, state and federal taxes are calculated as a function of property value, sales volume, income, or some other appropriate factor that varies with the size of the taxpayer – thereby ensuring that the tax burden is equitably spread across small and large firms.

Q. Does the same concern apply to residential gas customers?

A. Yes. If the JP is implemented as proposed, and the minimum system approach is fully implemented over the course of the three year rate plan, the Company will end up collecting approximately the same amount for its fixed ("minimum system") gas costs from a hypothetical 400 square foot studio apartment constructed in Queens shortly after World War I as it would collect from a hypothetical 3,500 square foot luxury apartment across the river in Manhattan – notwithstanding the fact that the latter apartment uses more than five times as much gas.

The anomalies and inequities associated with the minimum system approach used in the JP do not stop there. Under the minimum system approach, the amount of fixed costs recovered from a 10-unit apartment building could end up being <u>more</u> than the amount recovered from a much larger 100-unit apartment building down the street. This would occur where the landlord of the larger building obtains gas for all of its tenants through a single meter so each tenant counts as only 1/100th of a "customer," while the owner of the smaller building installs separate meters for each unit, so that each apartment in the smaller building is billed as a separate individual customer. From these examples, it is clear that equitable treatment cannot be achieved if the fixed costs are allocated and recovered on an equal per-customer basis, without any consideration of how large or how small different customers are, or how much or how little they use the gas system.

<u>The Number of Customers Is Not A Causative Factor for Gas Distribution Mains</u>

Q. You have acknowledged that the cost of distribution mains varies with mileage – the longer the main, the more costly it is. Does this fact change your opinion concerning the inequities of uniform per-customer cost recovery, or suggest the existence of a causal relationship between the number of customers and the cost of distribution mains?

A. No. As was noted in the Massachusetts order we quote below, even if a correlation is found between miles of distribution main and the number of customers (which has not been demonstrated for New York City or Long Island), that would not establish a cause and effect relationship between customers and mileage. To explain why this is so, consider first the fact that decisions by municipal authorities about the configuration and length of the streets in a municipal area, and decisions by the utility to install gas mains along those streets, both occur long before individual households and businesses decide whether or not to become customers of the gas utility. We do not deny that some of the planning decisions made by utilities might, under some circumstances, be influenced by the number of customers they anticipate will sign up for service after a main is installed. However, even where this is the case, the number of customers is typically being used as a simplified “rule of thumb.” To the extent this “rule of thumb” works, it is because no one becomes a customer unless they want to use natural gas. In other words, the number of customers does not actually cause the costs to be incurred, or drive the utility's decision to install the main, but rather it is the anticipated demand for gas.

The primary cause and effect relationship is straightforward: the decision to extend mains down specific streets is driven by expectations concerning future income from adding the main, which is driven by the demand for gas. Customers are only relevant to this causal relationship because it is customers that have demand for gas. But one or two potential large customers might be sufficient to cause a main to be installed down one street, while even a dozen potential small residential customers might not be enough to justify installing a main on another street – because the latter group doesn't use enough gas to justify making the investment. Of course, other causal relationships also exist, complicating the analysis – mains can sometimes be installed on streets with no customers, for instance, to help maintain pressure, or to move gas from a source of supply in one area, to serve a demand in another area.

<u>Prior Commission Decisions Regarding This Issue</u>

Q. When the Commission has a long-established and invariant way of handling a particular issue, the DPS Staff will not necessarily comment on the issue. Is this the situation with the classification and allocation of distribution gas mains?

A. No, that is not the situation here. The Commission has, on more than one occasion, accepted proposals to classify distribution gas main costs partly as demand-related and partly as customer-related. However, it has also accepted proposals to classify distribution gas main costs as entirely demand-related, as we recommend in this case, and the issue has been hotly disputed in multiple recent cases in New York, in addition to the current rate proceedings. In fact, putting the fixed portion of the cost of distribution gas mains into the customer classification has been a controversial practice since at least the 1980's, and it remains a controversial practice to this day, as we will discuss later in our testimony. While we realize the Commission has sometimes accepted this approach, we do not believe those past decisions should preclude consideration of the many problems that exist with the minimum system approach, and we urge the Commission to fully weigh the concerns we are raising here.

Q. Are you aware of any cases in New York where the Minimum System approach was not accepted by Staff?

A. Yes. In Case 06-G-1185 and Case 06-G-1185, involving KEDNY and KEDLI, DPS Staff recommended giving 100% weight to demand, despite the fact that the utility had developed a Minimum System Analysis. DPS Staff's stated rationale was to "more closely identify the minimum customer costs for each service class". (Direct Testimony of Aric Rider, page 15.) More recently, in Case 14-G-0494, a 2014 proceeding involving Orange and Rockland Utilities (which is owned by Con Edison), the Staff Gas Rates Panel recommended "allocating the costs of the distribution gas mains system on a 100% demand and 0% customer basis" despite the fact that the utility took a different approach, developing and relying on a Minimum System Analysis. (Staff Gas Rates Panel, p. 23) DPS Staff's position in the Orange and Rockland gas case was ultimately adopted by the Commission.

Similarly, in a 2008 Central Hudson rate proceeding (Cases 08-E-0887 et al.), Staff proposed classifying and allocation gas distribution mains in essentially the same way we are recommending here – based upon peak demand. In that case, Staff's proposal was not accepted, but there was nothing in the Commission's decision to suggest it intended to resolve the issue in a definitive manner that would control all future cases. To the contrary, the controversy in that case was largely resolved on the basis of the Commission's preference for rate continuity and the desire to avoid potential customer impacts that might result if it were to change allocation methods from what was historically the practice of that utility. The Commission explained its reasoning as follows:

> Staff proposed to reclassify gas distribution main costs for purposes of the pro forma embedded cost of service study by assigning them entirely to the demand component of rates. [This] reclassification results in a very large shift in cost responsibility from residential customers to large gas users. The RD noted that both the existing and proposed methodologies are deemed acceptable by NARUC with no indication that one or the other is superior. It concluded that such a large shift in cost responsibility should not be adopted without compelling evidence that it is necessary to rectify some serious inequity.
>
> (Order Adopting Recommended Decision With Modifications, pages 46-47.)

Q. Are you aware of any cases in New York where the utility allocated distribution gas mains using 100% peak demand?

A. Yes. In two recent cases, Case 15-G-0286 and Case 15-G-0284, and in some earlier cases, New York State Electric & Gas Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RG&E") classified and allocated their distribution gas mains using peak demand. In the 2015 cases, these utilities advocated essentially the same approach we are recommending in this gas case, although they gave weight to both customers and peak demand when classifying and allocating the analogous components of the electric distribution system. However, their decision to allocate the analogous electric costs based upon the number of customers was not based upon a preference for that treatment, or a substantive distinction between gas and electric distribution systems. Instead, this inconsistency was the result of an agreement reached in a Joint Proposal that resolved an earlier set of cases, Case 09-E-0715 et. al., where the utilities had proposed using 100% peak demand in both the electric and gas cases.

In Cases 09-E-0715, et al., the NYSEG and RG&E Embedded Cost of Service Panel was asked in its Rebuttal Testimony at pages 6 – 7, whether or not the costs of a hypothetical "minimum system" should be allocated in proportion to the number of customers, on the theory that these represent fixed costs that do not vary with peak demand. The Companies' witnesses gave several reasons why they disagreed with this approach, and explained that allocating the disputed costs based on peak demand "reflects a much better recognition of cost responsibility" and they noted they "used this approach in a consistent manner for all four cost studies" (including both of their gas ECOS studies and both of their electric ECOS studies).

NYSEG and RG&E's witnesses went on to point out flaws in the reasoning that had been offered in support of relying on a hypothetical "minimum system" to classify some costs as customer-related, thereby allocating the costs in proportion to the number of customers. In particular, the witnesses expressed concern because, in their view, this methodology tends to impose an unreasonable burden on small customers:

> The identification of any minimum installed system contains a corresponding load carrying capability. For small customers, which are the majority of NYSEG's and RG&E's secondary customers, this is a major component of load. The results simply over-allocate costs to the smaller residential and general customer classes, which are the majority of customers. In the final analysis, the proposed recognition of a customer component by both Staff and Dr. Rosenberg should be dismissed as flawed and unrepresentative of cost responsibility.
>
> (Rebuttal Testimony of NYSEG and RG&E's Embedded Cost of Service Panel, Cases 09-E-0715, et al., p. 8)

The reasoning behind their critique is straightforward: even if one separates out the hypothetical cost of a “minimum system,” in practice any such system will inherently have enough load handling capacity to accommodate the needs of very small customers – and thus it is inequitable to also require them to pay a pro-rata share of the remaining costs that are incurred to handle demands in excess of the minimum system. Accordingly, for the Minimum System Approach to be fair to small customers, they would need to be exempt from contributing toward the part of the system in excess of the hypothetical “minimum” – that is to say, the portion that is being allocated in proportion to peak demand. This is something the other parties failed to do in the 2009 NYSEG and RG&E rate cases (and which Con Edison did not do in this gas case).

NYSEG and RG&E's Embedded Cost of Service Panel emphasized this concern in defending their objection to the Minimum System Approach, and their preference for giving 100% weight to peak demand:

> Failing to do this extra step results in this load capability being ignored and the remaining non-minimum system costs being allocated on each class's total load, thereby creating a serious flaw - a "double dip" - which results in an over-allocation of these costs to smaller customer classes.
>
> (Rebuttal Testimony of NYSEG and RG&E's Embedded Cost of Service Panel, Cases 09-E-0715, et al., p.9)

<u>Decisions in Other Jurisdictions Regarding Distribution of Gas Main Costs</u>

Q. Has the Minimum System approach been universally accepted in other jurisdictions?

A. No. This costing approach has been under debate for more than 30 years, and the results of such debate have varied widely. The debate has been carried out sporadically across multiple jurisdictions and many years. In many cases the issue was not debated, and thus it is not readily apparent whether the approach was used, or how it would have been dealt with if the issue had come to the forefront.

Overall, it is fair to say that the Minimum System Approach is not universally accepted by either utilities or regulators. Where it has been discussed, it has often been very controversial. Even when it has been accepted, it had not necessarily been fully relied upon. Some utilities may analyze their costs based upon a hypothetical Minimum Distribution System (“MDS”) or a statistically-based variant of the concept called the zero-intercept (“ZI”) method, but they do not fully implement the concept in developing their actual revenue allocation and rate design proposals. Other utilities choose not to prepare this type of analysis, and instead classify and allocate all of the distribution accounts in question based 100% on demand, as we recommend in these cases.

Similarly, some state regulatory commissions may accept filings that include a minimum system analysis, but may not necessarily accept or reject the results, or may ignore or give little weight to the results when developing the actual revenue allocation and rate design they ultimately approve. In fact, the same jurisdiction may resolve the issue one way in one case, and another way in another case – depending upon the circumstances in each case, including how the issue was presented to it, and what evidence was available. Similarly, the issue might be resolved one way in the context of class allocations, and another way in the context of rate design. Examples of such state regulatory commission decisions are presented later in our testimony.

This diversity of results can be gleaned to a degree from a careful reading of the May 28, 2015 report by the American Gas Association ("AGA"), which we cited in our direct testimony. That report includes distribution gas mains and services in its list of "fixed" costs, which many of AGA's member utilities believe should be recovered through fixed monthly charges. However, the report goes on to note that many utilities actually recover only "a portion of these costs through a fixed charge on the customer's bill. This is most often called the 'customer charge,' but it is also called minimum bill. . ." (AGA Energy Analysis Report, page 1.) The report explains that cost recovery policies vary widely across utilities and jurisdictions, and concludes that, on average "[t]he customer charge…typically recovers only 46 percent of a utility's actual fixed costs…" (AGA Energy Analysis Report, page 2.)

The data provided in Appendix 1 to the AGA report shows that as of 2015, customer charges spanned a wide range both across jurisdictions and within jurisdictions. The report includes many examples from around the country where gas utilities have much lower customer charges or minimum bills than Con Edison, including: AGL – Florida City Gas in Florida ($8.00), Alliant – Interstate P&L in Minnesota ($5.00), Avista Corp in Idaho ($8.00), Avista Corp in Oregon ($4.25), Centerpoint Arkla in Arkansas ($9.75), Chesapeake Utility Corp in Maryland ($8.75), Coserv Gas in Texas ($7.00), Dominion – Hope Natural Gas in West Virginia ($8.99), Integrys – Wisconsin Public Service Corp in Michigan ($5.00), Liberty Utilities in Iowa ($7.95), Liberty Utilities in Illinois ($9.90), Middle Tennessee Natural Gas Utility District ($7.00), Montana-Dakota Utilities in North Dakota ($3.50), Montana-Dakota Utilities in South Dakota ($8.40), Northwestern Energy in Montana ($7.30), Northwestern Energy in Nebraska ($8.00), Piedmont Natural Gas in North Carolina ($10.00), Public Service Electric and Gas in New Jersey ($5.46), Questar Gas in Utah ($6.75), Sempra – Southern California Gas in California ($4.90), UGI Penn Gas in Pennsylvania ($2.19), Washington Gas Light in the District of Columbia ($9.90), Wisconsin Power & Light ($1.51), and many others. Given monthly rates like these, it is clear that many regulators are either rejecting the Minimum System concept, or they are largely ignoring it when deciding what actual rates to charge customers.

Q. Can you provide a few examples of cases where the Minimum System approach was rejected in other states?

A. Yes. One example is from Massachusetts, where the concept was advocated by an intervenor but rejected by the Massachusetts Department of Public Utilities:

> The Consortium contests the Company's classification of distribution mains as entirely capacity-related (id., p. 10). The Consortium presented Alan Rosenberg, a consultant with Drazen-Brubaker Associates, Inc., to support its capacity classification and allocation arguments . . . .
>
> The Consortium proposed that the Company conduct a study to identify and classify a minimum portion of distribution mains as customer-related . . . The Department has reviewed and rejected a similar argument in Colonial Gas Company, D.P.U. 84-94, pages 73 and 77-78 (1984) ("Colonial").
>
> In Colonial, the Department . . . found that the size of a distribution main is determined by the amount of gas that would be sent through a particular main during the peak time period. Id., p. 77. The Department found that distribution mains are capacity related . . . Moreover, the Department has previously found that the costs of distribution mains do not vary with the loss or the addition of a single customer. Western Massachusetts Electric Company, D.P.U. 20110-A, p. 13 (1982).
>
> The Department notes that a strong correlation between two variables does not necessarily indicate cost causation. Specifically, the fact that number of customers and length of mains are strongly correlated does not establish that number of customers is a significant factor relative to other factors in causing the Company to incur distribution mains costs. In this instance, the Department will not rely on a statistical measure without a demonstration that the hypothesis being examined is based on sound reasoning.
>
> The Department reaffirms its past findings and concludes that there is a cost causative relationship between loads and distribution mains. The Department finds that there is

> no need for the Company to conduct a study to identify and classify a portion of distribution mains as customer-related.
>
> (Order Dated October 31, 1991, DPU Case 91-60 (WL 531844).)

Another example is this case in Illinois:

> The arguments of IIEC and Wal-Mart do not persuade the Commission to deviate from its past decisions and now embrace the MDS. The MDS method fails to properly emphasize the purpose of the distribution system — that being to satisfy a customer's daily demand for electricity. Ameren's method, on the other hand, does not suffer from this weakness. The Commission also continues to believe that distinguishing the cost of connecting customers to the distribution system and the cost of serving its demand remains problematic. Moreover, the Commission is hesitant to rely on the 1992 NARUC manual cited by IIEC and Wal-Mart because of its age and the changes in the electric industry. Accordingly, the Commission will not adopt the MDS in this proceeding. The Commission also declines to adopt IIEC's suggestion that Ameren be required to present a COSS in its next rate case incorporating the MDS approach. In the Commission's view, it would be unreasonable to require Ameren to perform a COSS that incorporates a method repeatedly rejected by the Commission.
>
> (Order dated November 21, 2006 (Ill. C.C.) (WL 3863623).)

The Michigan Public Service Commission rejected the Minimum System concept in a 1989 case involving Consumers Power Company, choosing instead to use an allocation factor based upon average and peak (“A&P”) demand:

> Consumers and ABATE each proposed that a portion of Consumers' distribution mains — the minimum system —

> is customer related and should be allocated on a customer basis . . . The Staff proposed that all distribution mains be allocated pursuant to the A&P methodology.
>
> The ALJ determined that the Staff's allocation of distribution mains was reasonable and recommended its adoption by the Commission. In so doing, he noted the Commission's preference for the A&P allocation methodology and its recent rejection of the minimum system concept in Case Nos. U-8635, U-8812, and U-8854.
>
> The Commission finds the arguments raised by ABATE and Consumers are not persuasive. Any allocation methodology utilized by the Commission is, to some extent, arbitrary. Ideally, no customer should be assessed more than the exact cost of serving that customer. However, attaining this ideal standard would require a separate rate computation for each customer.
>
> In the final judgment, the question is not whether a more exact methodology can be constructed; rather the question is whether the method and result are reasonable. The Commission finds the method proposed by the Staff, which has been repeatedly utilized by the Commission in other cases, is an accepted and reasonable way to distribute the cost of Consumers' distribution mains. Accordingly, the exceptions filed by ABATE and Consumers are rejected.
>
> (Order dated December 7, 1989 in Case Nos. U-8678 et al. (WL 418755).)

Another example involved Mountaineer Gas Company, where the West Virginia Public Service Commission weighed extensive arguments back and forth before ultimately rejecting the Minimum System approach:

> Staff takes issue with the Company's use of the minimum system approach for allocating distribution plant . . . Staff recommends using class peaks as a better method of allocation of the distribution mains.

> Mountaineer maintains that the minimum system methodology presented in its class cost of service study is the better method because: 1) it is consistent with good allocation principles; 2) it is recognized by NARUC and approved by several state Commissions . . .
>
> Mountaineer disagrees with Staff and CAD's allegations that: 1) the minimum system is not based on cost causation; 2) that the minimum system places to much emphasis on number of customers; and, 3) that Mountaineer should allocate more of its cost based on through-put. . .
>
> Similar to the return on equity and rate of return issue, the Commission is faced with the testimony and exhibits of well qualified experts on rate design and three separate class cost of service studies. In the final analysis, the adoption of any of the parties' recommendations is a matter of judgment. The Commission is persuaded by the CAD's arguments regarding the Seaboard formula of allocating distribution system cost. The Commission is further persuaded by Staff and CAD's arguments that Mountaineer's class cost of service study places undue emphasis on allocating costs on the basis of the number of customers, which tends to unfairly allocate more costs to the residential customer.
>
> (Order dated October 29, 1993 in Case No. 93-0005-G-42T (WL 494175).)

Q. The Zero Intercept approach is sometimes offered as a compromise – a less objectionable alternative to a traditional Minimum System analysis. Can you describe the Zero Intercept Approach and provide some examples where this option was discussed?

A. Yes. One way of understanding the Zero Intercept Approach is to think of it as a variation of the Minimum System Approach, which focuses on an even more extreme hypothetical concept: a system consisting of mains with an interior diameter of 0 inches. These pipes are still very costly to purchase and install, but they cannot carry any actual gas. In practice, the Zero Intercept approach is developed by applying statistical techniques to the historical cost data, in an effort to distinguish between the fixed and variable components of the installed cost of mains. While it might be offered as a compromise or less objectionable approach, it is still controversial, and depending on the adequacy of the data and the specific statistical technique applied, it can result in cost estimates that are actually larger than the standard Minimum System Approach.

In a 2002 case involving Gulf Power Company, the Florida Public Service Commission rejected both versions, explaining their reasoning as follows:

> The concept of a zero load cost is purely fictitious and has no grounding in the way the utility designs its systems or incurs costs because no utility builds to serve zero load. There is no real equipment that equates to the costs identified by the ZI methodology. We have rejected MDS in the past for this very reason.
>
> (Order No. PSC-02-0787-FOF-EI dated June 10, 2002 in Docket No. 010949-EI (WL 1349501).)

That decision referred to the Florida Public Service Commission's history of rejecting the method, citing an example from more than 20 years earlier, where it had explained its fundamental discomfort with the concept:

> The Company and staff have proposed the use of a theoretical minimum distribution cost . . . we do not agree that a theoretical cost of a minimum distribution system is appropriate . . . The installation of the distribution system is made in anticipation of a projected level of actual use. The system does not contain a basic theoretical minimum distribution system. Reliance on such a mechanism is speculative at best.
>
> (Order 9599, issued October 17, 1980 in Docket No. 800011-EU.)

A similar decision was made in a 1984 case involving Puget Sound Power & Light, where the Washington Utilities and Transportation Commission rejected both options:

> The Commission rejects the company's use of the zero-intercept method. The minimum system method, of which the zero intercept method is a variant, is also rejected. Both methods are likely to lead to the double allocation of costs to residential customers and over allocation of costs to low use customers.
>
> (Order dated January 19, 1984 in Case No. U-83-26 (WL 1022551).)

Q. Can you provide an example of a case where the Minimum System approach was accepted, yet the regulatory commission expressed reservations about the concept?

A. Yes. In a 1984 case involving Enstar Natural Gas, the Alaska Public Utilities Commission stated:

> Although the Commission finds the overall methodology used in the COS study to apportion distribution costs results in a fair allocation among the classes, the Commission believes that future use of a minimum distribution study… may unfairly burden the residential class. From an optimal ratemaking perspective, there should be a direct cause and effect relationship between any cost and the object to which that cost is being allocated. While COS studies give the impression that the above relationship is quite precise, this is seldom the case, particularly when attempting to apportion the distribution expenses of an integrated natural gas utility. Distribution costs in general do not always have a strong positive correlation, nor do they necessarily vary directly with the number of customers, the type of class, the demand, or the consumption of gas. In sum, distribution costs are joint-use expenses not subject to precise allocation. In the final analysis, the decision to allocate distribution expenses must be resolved by rather subjective policy decisions; the decision becomes a value judgment based on concepts of fairness, reasonableness, optimum pricing, etc., and not objectively measurable allocation criteria.
>
> For these reasons, the Commission is not persuaded that a major portion of distribution expenses, "justified" via a hypothetically derived minimum distribution study, should continue to be automatically assigned to the residential class via a customer component allocator…
>
> (Order No. 6 in Case U-83-38, dated February 14, 1984.)

Q. Can you provide an example where a regulatory commission more firmly expressed its objections to the Minimum System approach?

A. Yes. About a decade after the Puget Sound case mentioned earlier, the Washington Utilities and Transportation Commission went even further in rejected it:

> The company proposed to classify distribution costs using the Basic Customer method, which treats substations, poles, towers, fixtures, conduit, and transformers as demand-related. Service drops and meters are classified as customer-related . . . .
>
> WICFUR and SWAP recommended use of the Minimum System approach. This would classify most distribution-related costs according to the relative number of customers in a class. WICFUR argued that this method better reflects the fact that a multitude of small customers requires a more extensive distribution system as compared to large customers with the same total energy requirements.
>
> The Commission finds that the Basic Customer method represents a reasonable approach. This method should be used to analyze distribution costs, regardless of the presence or absence of a decoupling mechanism. We agree with Commission Staff that proponents of the Minimum System approach have once again failed to answer criticisms that have led us to reject this approach in the past. We direct the parties not to propose the Minimum System approach in the future unless technological changes in the utility industry emerge, justifying revised proposals.
>
> (Order dated August 16, 1993 in Docket No. UE-921262 et al (1993 WL 13812140).)

Q. Can you provide an example where the utility was actually required to perform a Minimum System analysis, yet the results were ultimately rejected?

A. Yes. This occurred in a 2009 electric case involving Public Service Company of Oklahoma:

> Pursuant to the Commission's Order in PSO's last rate case, Cause No. PUD 200600285, PSO performed and filed a minimum system study that allocated a portion of the distribution costs in Accounts 364-368 on the basis of

> number of customers, instead of allocating those costs based upon demand. . . . Although PSO performed the minimum-system study as required, PSO did not utilize the minimum-system study in its cost-of-service study and advocated the continued allocation of the distribution costs in Accounts 364-368 on a demand-only basis, as has been approved by the Commission for PSO since the 1980s . . . .
>
> PSO explained that it used a demand-only allocator for distribution costs in Accounts 364-368 because the distribution system poles, wires, and conduit contained in those accounts are sized to meet the maximum load demand imposed on the system and the cost of those facilities does not vary directly with the number of customers . . . .
>
> The Commission finds that PSO's demand-only methodology for classifying distribution system costs in Accounts 364-368 is reasonable and finds that PSO's retail cost-of-service study should be accepted.
>
> (Order No. 564437 dated January 14, 2009 (2009 WL 512577).)

Q. If a regulatory commission has not explicitly rejected the Minimum System approach, does this necessarily mean it has accepted the approach?

A. No. For example, we did not find any orders in which the Idaho Public Utilities Commission made a decision to either accept or reject the Minimum System approach. Nevertheless, upon further investigation, we found testimony filed by Avista Utilities in a recent case (IPUC Case No. AVU-G-15-01), which explains that the utility allocated distribution mains using the same methodology it used in numerous past cases. While the witness does not explicitly mention the Minimum System approach, his exhibit describing the cost of service study shows that distribution mains were allocated 100% on demand, using a combination of Average Peak demand (annual throughput) and Coincident Peak demand.

Q. To wrap up this discussion, can you briefly explain what conclusion you reached from your review of cases in other states?

A. The Staff Gas Rates Panel has relied upon the Minimum System approach in developing their revenue allocation and rate design proposals, without providing any explanation or support for why it has chosen to do this. While the Minimum System approach has been used by New York utilities and accepted by Staff and/or the Commission in other cases, this does not mean the concept is universally accepted, nor does this sporadic pattern of past approval provide a valid reason for relying on a Minimum System analysis to establish rates in this gas case. The concept is fundamentally unsound, and we recommend that cost results based upon this methodology not be given any significant weight in this case.

D. Recommended Treatment of Disputed Costs

Q. Given the problems with the Company's "minimum system" approach, which was adopted in the JP, what alternative do you recommend instead?

A. We recommend classifying the entirety of Account 376 as demand-related and allocating it using a peak allocation factor – either the Company's Design Day Demand factor or the 1 Hour NCP factor. We recommend using this approach because it is has been used by other utilities and regulatory commissions and it offers a reasonable basis for analyzing costs, with the exception of temperature controlled and interruptible (IT) customers. Embedded cost-of-service based pricing is not appropriate for this group of customers. The assigned share of investment in transmission and distribution mains would approach zero in the Company's ECOS studies as well as our own studies based upon either 1 Hour Non Coincident Peak or Design Day Demand. Hence, the rate base allocated to these classes would be extremely small relative to their size, and thus any calculated class rates of return would be inordinately large. The resulting high percentage rates of return would not be meaningful, nor would 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 again, later in our testimony, when we discuss the Company's rate proposals for interruptible customers.

Q. Have you estimated the impact on our gas ECOS results for Con Edison's customers of using these two alternative options?

A. Yes. As shown on Page 2 of Schedule 2 of Exhibit ___ (UGRP-JP-1), we have developed a gas ECOS study that essentially replicates the data and methodology used by the Company with one key difference: we classified 100% of the costs in Account 367 as "demand-related" and allocated those costs to the various customer classes using the Company's 1 Hour Non Coincident Peak Demand allocator.

This one change results in noticeably higher rates of return for two of the individual customer classes, and lower returns for the other two classes. Most strikingly, the rate of return for SC-1 is 11.48% (far above the system average) using 100%

Demand, compared to 4.01% using the methodology proposed by the Company. This demonstrates the impact of the "minimum system" approach which places a much larger share of the cost burden on this class, because it has so many small customers, each of whom place very little demand on the system.

On Page 3 of Schedule 2 of Exhibit ___ (UGRP-1), we show what happens if 100% of the costs in Accounts 367 are classified as "demand-related" and allocated using the Company's Design Day Demand allocator. This demand allocator is used by some other New York gas utilities to allocate distribution mains. For example, in recent gas rate cases both NYSEG and RG&E allocated 100% of distribution gas mains using this allocator, and none of the costs were allocated using customers (i.e., the same approach we used on Page 3 of Schedule 2). Also, KEDNY and KEDLI used this allocator for the demand-related portion of distribution mains in their currently pending rate cases (Cases 16-G-0058 and 16-G-0059).

Comparing Pages 2 and 3 of Schedule 2 of Exhibit ___ (UGRP-JP-1) we see the choice of demand allocators has a relatively minor impact on the results, at least when compared with the impact of using customers rather than demand to allocate the disputed costs. For instance, the rate of return for SC-3 is 5.25% using 1 Hour Non Coincident Peak and 5.27% using Design Day Demand. The SC-1 class shows the largest difference: it has a return of 11.48% using 1 Hour Non Coincident Peak and a return of 12.35% using Design Day Demand.

V. REVENUE ALLOCATION

Q. How has the JP proposed to distribute the gas revenue increase among the various customer classes?

A. The JP relied heavily on the results of the Company's gas ECOS study. The Company began by calculating class-specific surpluses and deficiencies for class rates of return that fell outside a "tolerance band" of plus or minus 10% around the total system return shown in its gas ECOS study. In developing the proposed revenue allocation in the JP, the first priority was to increase rates for any class with a return below the tolerance band, and then spread the remainder of the rate increase on a more uniform basis across all classes. The JP applied one-third of the class-specific surplus or deficiency per rate year, so that over the course of the three Rate Years, 100% the calculated deficiency or surplus is used to shift the revenue burden between classes.

Q. Can you please discuss your response to the JP's gas revenue allocation proposals?

A. We disagree with the approach used in the JP, since it depends heavily on ECOS results which we believe are invalid. While one might argue that the JP makes an attempt to maintain a degree of "rate continuity," by phasing in the ECOS results over three years, all of the proposed percentage rate changes are closely tied to the ECOS results, and by the end of the Rate Year 3 the revenue burden is shifted between classes to eliminate the entirety of the calculated deficiencies and surpluses. Thus, it is fair to say that the revenue allocation used in the JP is driven by the results of a single ECOS study, to the exclusion of any other considerations. As we demonstrate in our Exhibits, if the same revenue allocation methodology were used with the results of either of our gas ECOS studies, all of the resulting class-specific percentage rate changes would be significantly different. Because the JP uses a highly mechanical approach to applying the results of this one ECOS study, any flaws in the Company's gas ECOS methodology adversely impacts individual customer classes to a far greater degree than if a less mechanical approach were used, such as one that relied more on an across-the-board approach to spreading the burden of the gas rate increase – like the approach used by KEDNY and KEDLI in Cases 16-G-0058 and 16-G-0059.

In general, we believe revenue allocation should not be a purely mechanical process that precisely 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 on to or off of specific classes based on the ECOS results), it is preferable to verify that similar results have occurred in other studies. The JP does not discuss or give any weight whatsoever to any other ECOS studies.

Q. Do you agree with the JP's gas revenue allocation proposals?

A. No. First, we strongly disagree with the proposal to increase rates for the SC-1 Residential and Religious class by more than the overall average increase. This proposal is entirely attributable to the Company's decision to allocate an unreasonably large share of the system's costs to this class through its ECOS's over-classification of costs as "customer-related." Because this class has so many small customer accounts it is burdened with a disproportionate share of the disputed costs. Conversely, this class is shown to be generating the highest return of all the customer classes under both of our ECOS studies, suggesting that these customers should be given a smaller percentage increase, rather than a larger one.

Second, we disagree with the manner in which the incremental revenue requirement attributable to Advanced Metering Infrastructure (AMI) is handled in the JP. While the JP does not explicitly discuss this issue, it appears to implicitly place most of the burden of AMI on small customers – those who are currently paying the highest delivery rates. The Commission has indicated that AMI cost recovery should be determined during rate cases. Yet, a substantial portion of the incremental revenue requirement in the JP is directly attributable to AMI and the JP is silent as to the manner in which this portion will be recovered.

The JP does not explain how AMI is being handled, but in the absence of an explicit allocation methodology, it appears the JP is implicitly allocating the AMI-related revenue requirement in proportion to delivery revenues. This effectively forces small customers to bear the brunt of the AMI cost burden, because these customers pay the highest delivery rates. This is not appropriate, since most of the benefits of AMI will flow to much larger customers, who are paying relatively low delivery rates.

We strongly disagree with this aspect of the JP, and agree with the approach recommended by the UIU Electric Rates Panel. The incremental revenue requirements associated with AMI should be allocated to customers based upon the flow of benefits to AMI. The flow of benefits is not proportional to delivery rates or revenues. To the contrary, many of the AMI-related benefits will flow to the Company's largest customers. For example, these customers will experience the greatest savings attributable to reductions in the commodity portion of their bill, and they are in the best position to reap the full benefit of the wealth of information that will be provided by AMI. Accordingly, we agree with the recommendation of the UIU Electric Rates Panel to allocate the AMI-related portion of the revenue requirement in proportion to energy usage. We have used this approach in developing all of the illustrative rates and typical bill comparisons included in our Exhibits.

Q. What are your recommendations concerning revenue allocation?

A. We recommend the Commission reject the revenue allocations included in the JP, because they are heavily biased against small customers to the benefit of larger customers. We recommend the revenue allocation be based upon a more reasonable approach to cost allocation, as we discussed above. Assuming this is done, 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, Con Edison's SC-1 Residential and Religious Non-Heat customers are paying very high effective rates per therm, as shown on Schedule 3 of Exhibit ___ (UGRP-JP-1), and these high rates are resulting in a very high class rate of return – 11.84% assuming the disputed costs are allocated using 1 Hour Non Coincident Peak Demand, or 12.35% assuming the disputed costs are allocated using Design Day Demand. Thus it would be reasonable to increase rates for the SC-1 Residential and Religious Non-Heat class by somewhat less than the other classes (the opposite of what is done in the JP, based upon a single flawed ECOS study).

Similarly, if a customer group currently pays relatively low rates, and this translates into a class rate of return that is significantly 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, some of Con Edison's SC-2 General Service II (Heat) customers currently pay relatively low effective rates per therm (particularly the largest customers in this class). As shown on Schedule 3 of Exhibit ___ (UGRP-JP-1), these rates have resulted in a class rate of return of just

3.23% or 2.96%, assuming the disputed costs are allocated using either the 1 Hour Non Coincident Peak or Design Day Demand, respectively.

We also believe rate continuity is important, and believe moderation is needed, to ensure no class experiences undue "rate shock." Hence, the degree to which specific rates are increased more than others will depend, to some degree, on the final revenue requirement approved by the Commission, and the extent to which other factors are considered by the Commission. In general, we recommend trying to achieve a moderate degree of convergence toward more uniform rates of return, without imposing extreme rate changes. We believe the Commission can best achieve this by giving significant weight to either or both of our ECOS studies, while also giving some weight to existing rate relationships, as well as other relevant concerns (e.g. affordability). We strongly recommend the Commission reject the revenue allocations included in the JP, because the JP is heavily biased against small customers to the benefit of larger customers.

As mentioned earlier, to assist the Commission with striking an appropriate balance amongst these various concerns, we prepared 9 Exhibits. Exhibit___ (UGRP-JP-2) through Exhibit ___ (UGRP-JP-4) illustrate the effect of using the JP's revenue allocation process in conjunction with our 1 Hour NCP-based ECOS study, while Exhibit___ (UGRP-JP-5) through Exhibit ___ (UGRP-JP-7) illustrate the same process in conjunction with our Design Day Peak-based ECOS study. Finally, Exhibit___ (UGRP-JP-8) through Exhibit ___ (UGRP-JP-10) illustrate an Across the Board approach which is similar to the one used in the JP in the KEDNY and KEDLI rate cases that are currently pending before the Commission. This latter set of Exhibits is also similar to the revenue allocation approach that was proposed by National Fuel Gas in its rate case, which is currently pending before the Commission.

Throughout these Exhibits we assumed the AMI-related portion of the revenue requirement will be allocated in proportion to therm usage, with the exception of Schedule 1, where we isolate and clarify the impact of the AMI portion of our recommendations. For instance, as shown in Exhibit___ (UGRP-JP-4), if the AMI-related revenue requirement is implicitly allocated in proportion to delivery revenues (as the JP appears to do), the rates paid by SC-1 Residential & Religious (Non-Heat) customers would increase by 2.53% in Rate Year 3. However, if the AMI-related revenue requirement is allocated in proportion to therm usage, these rates will increase by just 1.23%.

The impact of our AMI recommendation is most clearly delineated in Exhibit___ (UGRP-JP-10). If the AMI-related revenue requirement is implicitly allocated in proportion to delivery revenues, the rates paid by SC-1 Residential & Religious (Non-Heat) customers would increase by 6.68% in Rate Year 3, but if the AMI-related revenue requirement is allocated in proportion to therm usage, and the remainder of the revenue requirement is allocated in proportion to delivery revenues, these small customers' rates will increase by 5.29%. We believe the latter increase is more reasonable and consistent with the purpose of investing in AMI.

VI. RATE DESIGN

A. Background

Q. Before delving into the details of the JP's 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 JP's proposed 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 Company 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 Company's 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 to 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, issued February 26, 2015 in the REV proceeding, 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 JP seems to be taking at least one step toward advancing this goal – it does not propose to increase most of the existing 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 JP's 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 does the JP propose with respect to customer charges and volumetric gas rates for residential and small commercial customers?

A. As shown on Schedule 4 of Exhibit ___ (UGRP-JP-1), in its initial filing the Company proposed to keep most existing customer charges at the current level, and the JP follows suit. An important exception is the SC-1 Residential and Religious customer charge, which the JP proposes to increase from $18.60 to $19.75 in Rate Year 1, $21.75 in Rate Year 2, and $23.70 in Rate Year 3. The JP does not include a lot of detail concerning the volumetric rates that would be charged in each block of each tariff, but it appears the intent is to increase the volumetric rates by a relatively uniform percentage within each class, to achieve recovery of the revenue requirement allocated to that class. .

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

A. Not entirely. We agree with the JP's proposal to leave many of its customer charges unchanged. However, we think it is feasible to slightly reduce some of the customer charges in the first Rate Year and we don't think it is necessary to increase the SC 1 customer charge.

Q. How do the Company's 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 Company (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 goals 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 on 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 Company's gas ECOS study. 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 delivery 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 (the maximum rate at which gas is expected to be delivered through the service) during its economic life. The causation of this cost is therefore dependent in part on demand for 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 Company's gas customer charges compare to its customer costs?

A. Schedule 5 of Exhibit ___ (UGRP-JP-1) compares Con Edison's customer charges to its customer costs, based upon the Company's ECOS study, excluding distribution gas mains and services. As shown, in all cases the customer costs are lower than the current or proposed gas customer charges. For example, as shown on Page 1 of Schedule 5 of Exhibit ___ (UGRP-JP-1), for SC-1 Residential and Religious Non-Heat customers, Con Edison's current customer charge of $18.60 and the JP’s proposed increases to $19.75, $21.75 and $23.70 in Rate Years 1, 2 and 3 (respectively) are all higher than the corresponding customer cost, which is just $7.96 per month. Similarly, as shown on Page 1 of Schedule 5 of Exhibit ___ (UGRP-JP-1), Con Edison's current and proposed customer charge of $20.40 for the SC-3 Residential and Religious (Heat) is higher than the corresponding customer costs, which is just $15.70 per month.

A similar discrepancy exists for both of the Company with respect to the SC-2 General Service customers. The current and proposed rate of $30.45 exceeds the monthly customer cost of $22.75 for Rate I and $23.20 for Rate II.

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

A. We recommend the Commission not increase the Company’s fixed monthly charges for any customers. The proposed revenue increase should be collected exclusively through increases in these customers' delivery volumetric rates. Given the JP revenue requirement, we believe it would be appropriate to moderately lower the fixed monthly charges in Rate Year 1, rather than maintaining them at their current levels – since the current customer charges exceed the corresponding customer costs. For similar reasons, 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 consistent with, or lower than the level reflected in the JP, we believe the Company's rate design for most classes can be improved by increasing the tail block rate and lowering the customer charges at least a small amount.

By slowly transitioning rates in the direction we recommend, with less emphasis on the customer charge and greater emphasis on recovering revenues through 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 under the same rate schedule. We took a few small steps in this direction in developing the illustrative rates included in our Exhibits.

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

A. Yes. We recommend the Company 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 Company’s 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 Company’s residential and small commercial rate structures, we recommend that the Company 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 if so, 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. Non-Firm Gas Rates

Q. Would you please briefly explain how the Company's non-firm gas rates (i.e., SC12 Rate I, SC12 Rate II, etc.) differ from its firm gas rates?

A. Non-firm customers have not been analyzed and established in the same way as the rates paid by regular firm customers. Non-firm gas customers were not included in the Company's gas ECOS study, and their rates were not developed on a cost-of-service basis. The Company has historically been given considerable discretion to negotiate or establish "market-based" rates for non-firm customers, because they often have the option of using an alternative fuel (typically fuel oil), subject to some general constraints established by the Commission.

This ratemaking treatment was briefly discussed in the testimony of the Company's Gas Rate Panel:

> Firm gas customers pay rates for delivery service that are designed to recover the full cost of the Company's distribution facilities. Non-firm gas customers use the Company's gas delivery system when there is capacity available in excess of firm gas customer requirements. Because firm customers have a first call on the use of this delivery capacity, non-firm customers pay discounted delivery rates. However, the rate charged for non-firm

> service should be set so that non-firm customers pay fair value for the service they receive.
>
> (pre-filed Direct Testimony of Con Edison Gas Rate Panel, pp. 48-49.)

Consistent with the exclusion of these classes from the Company's gas ECOS study, non-firm customers have not been allocated or assigned any specific share of the Company's overall revenue requirement. Instead, firm customers have been responsible for meeting the entirety of the Company's gas revenue requirement, and then revenues received from non-firm customers have been treated as an ancillary source of income, which is used as an offset to that revenue requirement.

Q. Are the Company's non-firm rates relatively low, compared to rates paid by other customers?

A. Yes. These rates are well below the analogous rates paid by firm customers, and they are less than the rates that would maximize non-firm revenue margins for the benefit of firm customers. In other words, there is room to increase these rates without risking the loss of contribution from these customers due to bypass (obtaining gas from a different source) or switching to an alternative fuel.

As shown on Exhibit__(UGRP-JP-1) Schedule 3, firm customers obtaining gas pursuant to the regular tariffs are typically paying an average effective rate of 50 cents per therm (or more) for delivery service. As shown on Exhibit__(UGRP-JP-2) Schedule 4, even the largest firm customers (who pay some of the lowest regular rates) are paying approximately 30 cents per therm for gas delivery under the JP's proposed rates. The rates paid by non-firm customers for gas delivery are much lower, and the JP does nothing to reduce this discrepancy.

For example, customers whose estimated annual use of gas is at least 1 million therms, and who obtain gas using the Company's SC12 Rate II Off-Peak Firm delivery service, currently pay a fixed rate of just 8 cents per therm. And this rate is reduced to 7 cents per therm for monthly usage in excess of 500,000 therms per month. The Company originally proposed to increase these rates to 11.5 cents and 10.5 cents per therm, respectively. (Direct Testimony of Con Edison Gas Rate Panel, pp. 47-48.) Even with the Company's original proposed increase, these rates provide an effective discount of roughly 85% off the rate paid by the average firm customer and an effective discount of roughly 65% off the rate paid by the largest firm customers paying the regular SC-2 tariff rate. Yet, the signatories to the JP negotiated even more favorable treatment for these customers. Under the JP, these large, non-firm customers will not have their rates increased at all in Rate Year 1, and the increases in Rate Years 2 and 3 are just a fraction of a cent – far less than is being required of the firm customers.

Q. From the perspective of economic theory, are there benefits to having some customers that have dual-fuel capability, or are otherwise willing and able 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 non-firm 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 curtailable services have the potential to be a win-win arrangement for everyone – the interruptible and curtailable 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. maintaining dual fuel capability, or shutting down their 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 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. As the Company's Gas Rate Panel notes in its testimony, 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. Can you please elaborate on what Con Edison originally proposed with regard to non-firm gas rates in this proceeding?

A. The Company proposed to increase SC12 Rate II Off Peak Firm rates by approximately 3 cents per therm, which it describes as being "commensurate, on a percentage basis, with the increase in firm rates . . . since the inception of the off-peak firm rate." The Company's Gas Rate Panel explains:

> …the non-firm rate has not been adjusted in many years, during which time firm gas rates have increased as has the cost of the facilities used to provide service to non-firm customers. Moreover, the Company believes that in recent years the value of gas transportation service has increased and it seems reasonable that the contribution to the cost of facilities by non-firm customers to firm customers should reflect that higher benefit.
>
> (Direct Testimony of Con Edison Gas Rate Panel, pp. 48-49.)

As mentioned above, in support of this proposal, the Company's Gas Rate Panel quoted from a 1995 Order involving Long Island Lighting Company, in which the Commission concurred with the stated goal of maximizing interruptible revenue margins "for the benefit of core firm service customers, [which 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, supra, at p. 9.)

Q. What does the JP propose concerning non-firm gas rates?

A. The JP proposes that SC12 Rate 2 rates will remain during RY 1 at 8 cents per therm. In Rate Year 2 this will increase by 0.25 cents to 8.25 cents and in Rate Year 3 it will increase by another 0.50 cents, to 8.75 cents per therm. (See JP at 70) These are very small increases on rates that are already well below the value of the service being provided to these customers.

Q. What do you recommend concerning non-firm gas rates?

A. Considering the unique characteristics of interruptible and curtailable 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 non-firm gas 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.

While we understand the tradeoffs that are involved with reaching a negotiated settlement, we are troubled by the inordinately favorable treatment given to large customers receiving gas delivery under SC12 Rate 2. These customers are currently receiving discounts equivalent to 75% or more relative to the rates paid by other customers under the standard tariffs, and these heavily discounted rates have not kept pace with recent changes in the value of the service being provided (e.g. considering the cost of natural gas relative to other fuels). Under these circumstances, we disagree with the decision to completely exempt these customers from any increase in Rate Year 1, and to increase their rates by less than a penny a therm during Rates Years 2 and 3. In sum, we recommend the Commission consider increasing non-firm rates to a moderate extent beyond that reflected in the JP, while maintaining a reasonable discount relative to firm service.

Q. Does this conclude your direct testimony in response to the JP, which was prefiled with the Commission on October 13, 2016?

A. Yes.