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 13-E-0030
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 13-G-0031
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Steam Service.	Case 13-S-0032

DIRECT TESTIMONY

OF

UIU RATE PANEL

Dated: May 31, 2013
Albany, New York

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Table of Contents

I. INTRODUCTION AND OVERVIEW

Q. Would the members of the panel please state your names and business addresses?

A. Ben Johnson, 5600 Pimlico Drive, Tallahassee, Florida and Danielle Panko, 99 Washington Ave., Suite 1020, 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. Over the course more than 35 years, I have been actively involved in more than 400 regulatory dockets, involving electric, natural gas and other utilities. The vast 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 clients as well, including large industrial consumers and non-profit entities like the AARP.

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. I have not previously testified before this Commission.

(Panko) I currently hold the position of a Utility Analyst III with the Utility Intervention Unit ("UIU") of the New York State Department of State's Division of Consumer Protection representing residential and small commercial utility consumers. I received a Bachelor of Science degree in Mathematics from the State University of New York at New Paltz in 2001 and a Master's of Science in

Electrical Engineering from the State University of New York at New Paltz in 2008.

My first employment was with Central Hudson Gas and Electric located in Poughkeepsie, New York from 2000-2001 where I held two internships; first in the Accounts Service Department and later in the Electrical Engineering Department. In 2004, I joined Philips Semiconductors in the Integration and Reliability Department located in the IBM Plaza in East Fishkill, New York, where I held various reliability engineering positions with increasing responsibilities. In 2007, I joined Consolidated Edison ("Con Edison" or "the Company") in the Rate Engineering Department – Division of Finance located at 4 Irving Place, Manhattan, New York, as a Rate Analyst in the Gas Rate Design Section. In 2009, I was promoted to Senior Rate Analyst with increasing responsibilities in the same section. In 2012, I began my employment as a Utility Analyst III with the Utility Intervention Unit of the New York State Department of State's Division of Consumer Protection ("UIU"). My primary responsibilities include participating in New York utility rate cases, monitoring Public Service Commission proceedings, and attending New York Independent System Operator market meetings. I have not previously testified before the Public Service Commission ("PSC" or "Commission").

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

A. Yes, Exhibit ___ (URP–1) through Exhibit ___ (URP–7) accompany our testimony. All of these exhibits were prepared by us or under our supervision. Exhibit ___ (URP-1) contains four pages of information concerning allocation factors. Exhibit ___ (URP-2) is a succinct three-page summary of the results of our recommended cost allocation approach, along with some comparisons to the Company's cost study results. Exhibit ___ (URP-3) contains a two-page comparison of the customer class surpluses and deficiencies developed in the Company's cost studies and in our cost studies. Exhibit ___ (URP-4), consisting of four pages, compares the revenue distribution proposed by the Company with our recommendations. Exhibit ___ (URP-5) is a two-page summary of the results of our analysis of customer costs in comparison with the Company's current and proposed customer and minimum charges and our recommended charges. Exhibit ___ (URP-6), consisting of 11 pages provides illustrative rate information to help clarify and explain our rate design recommendations. Exhibit ___ (URP-7) contains 31 pages of typical bill comparisons, based upon these illustrative rates. The information in URP-4 through URP-7 is strictly illustrative. The precise rate changes that should be applied to each class will, of course, require more refined calculations, to ensure precise recovery of the actual revenue requirement that is ultimately determined and approved by the Commission.

In addition, we have assembled Exhibit ___ (URP–8), which contains 100 pages of responses to Information Requests ("IR") referenced in our testimony. Exhibit ___ (URP–9) is the Con Edison Rate Case Technical Conference presentation dated March 11, 2013, also referenced in our testimony.

Q. What is the nature of this testimony?

A. We are testifying as a panel on behalf of the UIU concerning the Company's requested rate and tariff changes, particularly with respect to the Company's embedded cost of service study, what portion of the requested rate increase should be paid by different classes of customers, various aspects of the Company's rate design, and a few other miscellaneous issues.

Q. How is your testimony organized?

A. Following this introduction, our testimony has seven additional sections. In the first additional section, we briefly discuss the background of this proceeding and briefly summarize our recommendations. In the next section, we summarize Con Edison's cost of service methodology and rate design proposals. In the third additional section, we discuss embedded, fully allocated, class cost of service studies, and some of the problems and limitations that inherent in these types of studies. In the next section, we discuss in greater detail the methodology the Company used to classify and allocate various costs to customer classes, with a particular focus on how Con Edison allocated certain fixed costs. Following that section, we discuss the Company's proposed revenue distribution and offer some suggestions for an alternative approach. In the sixth additional section, we discuss customer charges, minimum gas charges and declining block rates. Finally, we discuss miscellaneous other issues including Voluntary Time of Use rates, Energy Service Company (“ESCO”) billing data, Bill Payment Processing costs, and Automated Meter Reading issues.

Q. Would you please briefly summarize your recommendations?

A. Yes. The Company's embedded cost studies include many calculations which are based upon, or heavily influenced by, data from a small number of customers. This data is extrapolated in an attempt to generate estimates for large numbers of customers – similar to the manner in which estimates concerning public opinion are developed from the results of calling a sample group of potential voters. Unlike polling firms, however, Con Edison has not provided confidence intervals for any of the estimates they developed from their sample data, and some of the samples they relied upon were extremely small. Because they have relied upon very small sample sizes, all of the conclusions reached in the Company's cost studies – including those we are not specifically disputing – should be viewed with some skepticism. At best, the numbers presented in the study results (e.g., cost of services for different types of customers; the number of customers per service) should be viewed as rough approximations, with an unknown "margin of error" that could be very substantial.

In addition, we fundamentally disagree with the Company's approach to allocating certain "fixed" costs. We agree these costs do not vary with respect to monthly fluctuations in peak demand or energy usage, but they also don't vary with respect to fluctuations in the number of customers connected to the system – a fact that undermines the Company's rationale for allocating a large fraction of these costs to residential and small business customers.

To a large extent, the costs in question are "joint" costs which vary with the number of miles of streets served, and not the number of customers who are, or will be, connected to the system. Unlike the Company's proposals in this case, in competitive markets the recovery of joint costs is based upon the strength of demand from different types of customers, and in that sense, reflects the extent of the benefits received from the joint production process.

We recommend recovering more of these "joint" costs from larger customers, to be fairer and more consistent with the way the manner in which these types of fixed costs would be recovered in a competitive market, where the larger customers, who gain more value from using the system, make a larger contribution toward recovery of these costs. We would also note that the calculations developed by the Company in its effort to use the results of its cost studies are unnecessarily complex and convoluted. We recommend using a simpler, more straightforward approach to distribute the rate increase across customer classes.

Our analysis of embedded costs also influenced our recommendations concerning the Company's existing and proposed rate design. Once the joint costs are appropriately analyzed, it becomes apparent that many of the Company's customer charges and minimum charges are currently higher than necessary or appropriate. We recommend the Commission not increase these rates in this proceeding, since they are already at relatively high levels, and it would advance the public interest to recover more of the Company's fixed costs through volumetric charges – which will encourage energy conservation and be more consistent with the analogous pricing patterns observed in most unregulated markets. Going one step further, we recommend the Commission modestly lower Con Edison's customer and minimum charges, particularly if the overall revenue increase approved by the Commission is lower than requested by the Company, which would ensure that this can be accomplished without imposing an excessive percentage increase on the bills of larger customers.

We have similar recommendations with respect to declining block rates. Eliminating declining block rates removes the economic disincentive for customers to conserve energy, and it strengthens the incentives for customers to invest in more energy efficient appliances, add insulation, adjust thermostats, and take other steps to use less energy. The reasoning holds true for both gas and electric services.

For electric services, we recommend the Commission continue on the path of phasing out the existing declining block rates and, where feasible, move toward modestly inclining block rates (with higher rates in the final block of usage). For gas services, we recommend the Commission begin flattening the existing declining block rates, similar to what the Commission approved in the Company's last electric rate case.

Additionally, we provide recommendations concerning certain other issues. We disagree with the Company's proposals for residential time of day rates, and present some alternatives to those proposals. We also recommend the Company launch a web-based historical utility bill calculator in addition to other tools to allow customers to compare the Company's rates to those charged by various ESCOs, in a meaningful “apples to apples” comparison, using data from the Company's billing records reflecting the actual amount of energy used by the customer during the prior year.

We also raise some concerns related to the Company's Billing and Payment Processing Charge (“BBP”) and related costs. We do not see any compelling need to increase the BPP charges at this time, and think the Company should first make a greater effort to minimize these costs, by encouraging customers to opt for less costly ways of receiving and paying their bills. With respect to Automated Meter Reading (“AMR”) we recommend the Commission require the Company to develop a plan for gathering, organizing and analyzing data concerning its experience with both the Saturated and Strategic AMR investment programs and to evaluate whether these programs should be continued at the current pace, or slowed, stopped, accelerated, or modified.

This evaluation should include appropriate recognition of the value of information that can be obtained by deploying additional smart meters. Among other benefits, by investing in additional hardware and software that allows periodic collection of detailed usage data from a reasonably large sample of smart meters installed as part of both the AMR programs, the Company could greatly expand its load research data collection efforts. This would also allow the Company to gain valuable hands-on experience with many other aspects of state-of-the art metering – experience that could prove highly valuable if and when the Company decides, or is ordered, to move toward widespread deployment of “smart grid” systems.

II. BACKGROUND

Q. Can you briefly discuss the Company's previous rate case?

A. Yes. The Company's previous rate case was initiated on May 8, 2009 when Con Edison filed an application to increase its electric rates. (See, March 26, 2010 Order, Case 09-E-0428.) In its application, Con Edison requested a rate increase of approximately $854.4 million, or 7.4% on a total bill basis. (Id.) On November 24, 2009 Con Edison, Staff of the Department of Public Service ("DPS Staff") and various other parties filed a Joint Proposal. The Joint Proposal established a three-year rate plan designed to be equivalent to a revenue increase of $540.8 million in revenues on an annual basis starting on April 1, 2010; an additional $306.5 million on April 1, 2011; and an additional $280.2 million on April 1, 2012. To mitigate the impact of these increases on customers, the Joint Proposal provided that the three rate increases would be implemented on a levelized basis set at $420.4 million in each year. On average, the overall bill impact equated to an increase of approximately 3.6% in each year. (Id.)

With regard to revenue allocation, the Joint Proposal provided for some movement towards the results of the Company's embedded cost of service study, but did not fully implement it. The Joint Proposal also provided for a gradual movement away from declining block rates. (Id., p. 35.) The Commission approved the Joint Proposal on March, 26, 2010.

Q. Would you now provide some brief background information concerning this current docket?

A. Yes. This docket was initiated on January 25, 2013 when the Company filed amendments to certain electric, gas and steam tariff schedules. (See, Notice of Suspension of Effective Date of Major Rate Changes and Initiation of

Proceedings, January 29, 2013.) The Company is requesting an electric delivery base revenue increase of approximately $375 million, or a 7.2% increase in delivery revenues, and a 3.3% increase in customers' total bill. For gas, Con Edison is requesting a delivery base revenue increase of approximately $25 million, which is a 2.6% increase in delivery revenues and about a 1.3% increase in the average customer's total bill. (Id.)

III. CON EDISON'S COST OF SERVICE METHODOLOGY

Q. Please briefly summarize Con Edison's proposals in this phase of the proceeding, beginning with its cost of service study.

A. The underlying foundation for Con Edison's proposed rate design and revenue distribution was an Embedded Cost of Service study ("ECOS"). The ECOS study was developed using a two-step process. The first step involved functionalization and classification of costs to various operating functions (e.g., transmission, distribution, customer accounting and customer service) "with further division into sub-functions, such as distribution demand, distribution customer, services, overhead and underground." (Demand Analysis and Cost of Service Panel, p. 30.) Next, the functionalized and classified costs were allocated to specific service classes using various allocation factors. An ECOS study was also prepared for gas services, using a similar two-step process. (Gas Rate Panel, p. 14.)

Q. Can you explain the "functionalization," "classification" and "allocation" steps in a little more detail?

A. Yes. In the electric industry, the major functions are generation, transmission and distribution. In the natural gas industry, the major functions are production, storage, transmission and distribution. The Demand Analysis and Cost of Service Panel (at pp. 30-31) explained:

> The functionalization and classification step assigns the broad accounting-based cost categories to the more detailed categories employed in the ECOS study. This level of detail is required to differentiate, for example, demand-related costs from customer-related costs. This allows for the proper allocation of these costs to the classes based on cost causation.

Along with organizing costs in accordance with these major functions, the Company also classified costs into a few broad categories, based upon its view of what factors these costs are most closely related to. For instance, in the electric study costs were classified as demand-related, energy-related or customer-related. In the gas study, costs were classified as demand-related, commodity-related or customer-related.

In its electric study Con Edison classified as demand-related those costs it viewed as “fixed costs created by the loads placed on the various components of the electric system.” (Id., p. 31.) Similarly, in the gas study it classified as demand-related those costs it viewed as “fixed costs created by the on-peak hourly loads placed on the various components of the gas system.” (Gas Rate Panel, p. 15.)

Energy and commodity related costs were viewed narrowly by the Company. In developing these classifications it completely excluded any consideration of fixed costs required to provide electrical energy and gas to its customers. Instead, the energy-related classification was limited to variable costs directly related to the total kilowatt hours delivered during the year (electric) and the commodity-related classification was limited to variable costs directly related to the total quantities of gas delivered during the year.

Finally, Con Edison classified as customer-related the remaining portion of its “fixed costs” that it did not classify as “demand related.” It views these costs as being caused by the presence of customers connected to the system, regardless of the amount of their usage.

The final step, “allocation,” involves applying percentage factors to spread the costs in the various classifications to particular customer classes and rate schedules. The Company did not provide much detail concerning the judgments it made in this regard, except to argue that costs were allocated “based on the appropriate demand, commodity/energy or customer allocation factors.” (See, Gas Rate Panel, p. 16; Demand Analysis and Cost of Service Panel, p. 32.)

Q. How does Con Edison summarize the results of its cost of service study?

A. Con Edison presents its electric ECOS results in Exhibit___ (DSC-2), Table 1. Table 1 shows an overall system rate of return of 10.88%. It computes rates of return for individual customer classes that vary from 2.64% (Electric Traction NTD-SC #5) to 15.13% (Bulk Power TOD-SC #13). It computes the rate of Return for the Residential and Religious service class as 10.67%. Similarly, Exhibit___(GRP-1), Table 1 presents the rates of return for gas services. This table shows a total system rate of return of 7.54%, and individual class rates of return ranging from 6.92% (Residential and Religious SC No. 1) to 9.58% (General Heating SC No. 2H).

IV. FULLY ALLOCATED EMBEDDED COSTS

Q. Please turn to the next section of your testimony. Can you provide a brief description of fully allocated embedded cost studies, and explain what they measure?

A. Certainly. Fully allocated cost of service studies divide total test-year revenues, rate base, and operating expenses among the various customer classes to estimate the rate of return earned from each class. Many of these costs are either joint or common costs not directly attributable to any one customer class; therefore, they must be allocated by a formula. This opens the door to subjective judgments, and the results of the study tend to depend heavily on the particular allocation formulas chosen by the analyst.

Because they are based upon embedded costs, these studies do not report direct cause-and-effect relationships between the consumption decisions of the class members and the costs incurred by the utility. Thus a "cost" is not necessarily the actual expense that a particular group of customers imposes on the system. For instance, if a particular group of customers were not served by Con Edison (or had never existed), the Company's total costs would not necessarily be reduced by the amount attributed to that group of customers in the Company's ECOS study.

Embedded cost of service studies have long been used by this Commission and other regulators as a tool that can assist with the process of 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.

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

A. No. Embedded cost allocation studies are simply a technique for evaluating the relative fractions of the total revenue requirement that can reasonably be recovered from each class. At best, these studies provide a yardstick for judging whether or not each customer class is paying an 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 served by the same utility, 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 that is used in preparing the study. The problem lies neither with the people performing the studies nor with the amount of effort and resources devoted to the analysis. Rather, it is inherent in the very concept of allocating embedded costs.

Many of the costs incurred by public utilities are driven by external factors (e.g., zoning laws and the configuration of roads within the Company's service territory) as well as management and engineering decisions which reflect many different considerations. These external factors, management decisions, and engineering judgments are completely outside the control of individual customers or customer classes. These costs are influenced by numerous factors, decisions and judgments that cannot possibly be traced to individual customers or customer classes. To the extent the Commission wants to pursue the goal of insuring that each customer class pays the costs that it causes, it simply is not possible to achieve this goal by allocating historical accounting costs.

Q. Are you saying that some of the fixed costs the Company classifies as “customer costs” are not actually determined by the number of customers on the system?

A. Exactly. Even when the actions of particular customers, or the number of customers in a particular class, influence these types of costs, the linkage is largely indirect, and it is obscured by the passage of time. For instance, various customer decisions concerning what types and sizes of homes to occupy may have influenced management decisions and engineering judgments concerning the size and type of distribution system investments and related operating costs that were present during the test year. However, these customer influences are almost entirely traceable to actions (and anticipated actions) by customers that occurred years ago, when houses were initially constructed and distribution lines were originally planned and installed.

In truth, the cause and effect links between today's customers (or the customers present during any given year) and the costs incurred during that year are inherently impossible to measure using the techniques that are available for developing an embedded cost of service study. All of the various alternative allocation formulas rely upon statistics relating to a specific year, and none of them can possibly reflect with exactness the historic relationships of cause and effect that help explain the embedded accounting costs reflected in that year's data.

For these and other reasons, there is no "perfect" formula for allocating most, if not all, of the costs incurred by Con Edison. This is particularly true with respect to the cost of gas distribution mains and the electric distribution plant. Some cost allocation experts will sometimes imply their approach is the one and only "true" answer, and that any significantly different approach is a heresy not to be condoned. We disagree with that viewpoint. There is a substantial body of economic literature which convincingly demonstrates that there is no "correct" method for allocating joint and common costs, and that any attempt to locate the perfect method will ultimately prove fruitless.

Embedded cost allocation studies are simply a technique for evaluating the relative fractions of the total revenue requirement that can reasonably be recovered from each class. At their best, these studies can provide a useful yardstick for judging whether or not each customer class is paying a fair and appropriate share of the joint and common costs. Hence, a debate over different cost studies or allocation methodologies is, at its core, a debate over whether certain approaches are more reasonable than others.

Aside from the long lags that typically occur between when costs are planned, contracted, and incurred and when those costs are recovered through rates, there is an even more fundamental problem. Most of the Company's embedded costs are not caused by the actions of particular customers or customer classes; rather, they are incurred by management based upon an evaluation of the needs of the system as a whole. Thus it is not feasible, or meaningful, to rely entirely on an evaluation of causal relationships in deciding on the most reasonable allocation method.

Consider, for example, a hypothetical utility where 20% of its investment in distribution plant can be directly and meaningfully traced to historical decisions by customers concerning whether or not to use natural gas or electricity for heating, as well as the specific appliances and insulation they choose to install in their homes and places of business. The remaining 80% of the investment is entirely attributable to other factors – like the geography of the Company's service territory, the arrangement of roads and streets that have been constructed by local government over the course of decades, and zoning and other regulations that specify the number of buildings and the size of the buildings that can be constructed along each street.

In some sense, it's fair to say the 80% of the total costs that cannot be traced to customer decisions are fixed costs due to the presence of customers connected to the system, regardless of the amount of their usage. But, it would be equally fair to say those costs are fixed costs due to the existence of a system that is designed and engineered to provide utility service to all parts of the utility's service territory – regardless of how many customers are actually connected to that system. In other words – the key attribute of these costs is simply that they are fixed – and they are not necessarily caused by (nor do they necessarily vary with the number of) customers.

In general, the requirement in a fully allocated cost-of-service study that all costs must be allocated, regardless of how ambiguous the causal relationships, produces results that are defined by the particular allocation methodology selected, rather than by established economic costing principles. Thus, any number of widely different estimates of "cost" could be produced for a given service category, merely by changing the allocation procedure. One study might show a particular customer category earning an above-average rate of return, while another study of the same company during the same year might show a negative return for that same category. The allocation scheme is pivotal. These allocation decisions are highly judgmental and (not surprisingly) controversial in regulatory proceedings where fully allocated studies are introduced--particularly where the joint costs are a very substantial fraction of the firms total costs.

In evaluating the relative merits of different approaches, we believe it is important for the Commission to give adequate recognition to the basic being delivered by Con Edison: electrical and gas energy. Any allocation method that slights the importance of the most fundamental measure of the Company's output (kilowatt hours of electricity or therms of gas delivered through the system) should be viewed with skepticism. Where there is no clear cause-and-effect relationship between customer actions and costs, kWh and therms provide a reasonable basis for allocation, because they closely reflect the benefits received by each class from the investments and expenses in question.

V. DETAILED CRITIQUE OF CON EDISON'S ALLOCATION APPROACH

Q. Are there certain pervasive problems with Con Edison's cost of service studies?

A. Yes. One problem is particularly significant and pervasive. The Company's embedded cost studies include many calculations which are based upon, or heavily influenced by, data from a small number of customers. This data is extrapolated in an attempt to generate estimates for large numbers of customers – similar to the manner in which estimates concerning public opinion are developed from the results of calling a sample group of potential voters. When this is done by reputable polling firms, they usually state a “confidence” interval for their results. With a typical sample size of 600 or more potential voters, it's often impossible to predict the outcome of an election with any degree, and that's why the margin for error can be quite wide (e.g., plus or minus 4%), except when they use a relatively large sample – say, 1,200 or more potential voters.

In contrast, in this case, Con Edison has not provided confidence intervals for any of the estimates they developed from their sample data, and some of the samples they relied upon were extremely small. Perhaps the most extreme example, is for SC-1 Residential “Strata A”, where the Company used data for a single overhead customer in an attempt to estimate data for 18,662 overhead customers. Similarly, Con Edison used a sample of 21 underground customers to estimate data for the 391,905 customers in SC-1 Residential “Strata A”. (Exhibit ____ (URP-8), Attachment to City of NY IR No. 137.) As another example, Con Edison used a sample of just 6 overhead SC-2 customers in Strata B to estimate data for 27,473 overhead customers in that strata. With such small sample sizes, all of the conclusions reached in the Company's cost studies – including those we are not specifically disputing – should be viewed with some skepticism. At best, the numbers presented in the study results (e.g., cost of services for different types of customers; the number of customers per service) should be viewed as rough approximations, with an unknown "margin of error" that could be very substantial.

Q. Are there any specific allocation factors that you disagree with, and which are particularly important in understanding your disagreements with Con Edison's embedded cost of service study?

A. Yes. On the electric side, we particularly disagree with the portion of the Company's study which relies upon the "C01" allocation factor, to allocate costs in the category it calls "O.H. Lines - Customer Component" and the portion which relies upon the "C02" allocation factor, which is used to allocate costs in the category it calls "U.G. Lines – Customer Component."

> The C01, O.H. Lines – Customer Component, allocation factor consists of the number of overhead services. The C02, U.G. Lines - Customer Component, allocation factor consists of the number of underground services. No overhead and underground lines customer component costs were allocated to the street lighting classes or to those classes served at high tension.

(Exhibit__ (DAC-2), p. 15.)

Similarly, on the gas side we particularly disagree with the "C01" allocation factor, which the Company calls "Customer Footage of Mains." (Exhibit__(GRP-1), p. 10.) This factor was used to allocate what the Company describes as "the Distribution Customer Component." (Id.)

We disagree with the manner in which the Company analyzed the cost of "services" -- in essence, the part of the system that delivers energy from the distribution line running down the street to the customer's meter. In the gas study, these costs were allocated using the "C02" allocation factor, which is described in this manner:

> "Year-end book cost of services used for connecting customers to the distribution system. This allocation was based on a sample of service costs in each customer class."

(Exhibit__ (GRP-1), p. 10.)

In the electric study, the analogous costs were allocated using the "S03" and "S03A" allocation factors, which were described as follows:

> S03: Services – Overhead
> S03A: Services – Underground
>
> The year end book cost for the services allocation factors S03, Overhead Services and S03A, Underground Services were developed using the sample services study. The number of actual services installed for each class was estimated based on a sampling of customers from each class. The class samples were subdivided into energy usage strata levels and the number, size and book cost of service wires were obtained for each sample customer.

Q. What is the underlying premise supporting these allocation factors?

A. As we explained earlier, Con Edison argues that "Customer-related costs are fixed costs that are caused by the presence of customers connected to the system, *regardless of the amounts of their demand or energy usage."* (Emphasis added). On this basis, it prefers to recover these costs through the monthly customer charge, or minimum bill – a flat monthly amount that is paid by customers regardless of the extent to which they use, or benefit from, the system. Similarly, it has chosen to allocate these costs in a manner that is not related to demand or energy usage, and instead relies on assumptions and data that are closely tied to the number of customers, or number of services used by each class.

Q. Why do you disagree with Con Edison's cost allocation approach?

A. As indicated earlier, we fundamentally disagree with the Company's view of the costs. We agree that these costs are largely, if not entirely, what economists would describe as “fixed” costs – they are costs that do not change much from day to day or even from year to year. While we agree these costs do vary with respect to monthly fluctuations in peak demand or energy usage, they also does not vary with respect to fluctuations in the number of customers connected to the system.

Admittedly, the number of services is correlated with the number of customers – but the number of services is actually a function of the number of buildings connected to the system, and their configuration, rather than the number of customers. While there are cases where a service is used by a single customer, in other cases the same service connects multiple customers to the rest of the distribution system.

The entire distribution system – including both the portions running down the street and the portion running from the street to the meters – is designed to accommodate customers' peak demands. On that basis, both the fixed and variable costs of the system are sometimes allocated on the basis of peak usage or demand data. But it is even more fundamentally true that the fixed costs of the distribution system are incurred for the purpose of distributing gas or electricity to customers. While peak demand may be the focus of the engineering design phase, the opportunity (or need) to extend the system down additional streets, to serve potential new customers, is not driven by anticipated peak demands, so much as the opportunity to efficiently deliver a large volume of energy to one or more buildings in a particular area over the anticipated life cycle of the system.

The economic value that will be provided by the system over its entire life cycle is primarily a function of the anticipated volume of energy that will be distributed through the system. If the anticipated volume of energy to be distributed to a particular part of the city, or set of buildings, were negligible, there would be no economic incentive to create the delivery system in the first place (nor would there be much reason for government authorities to require the system to be built into those areas). In fact, some parts of the United States do not have a natural gas distribution system for precisely this reason, despite the existence of businesses and residences in the area. In other words, the existence of potential customers alone is not sufficient to justify building a distribution system – if those customers are fulfilling their energy needs using propane, fuel oil, solar, or other energy sources, and they have no desire to switch to natural gas – or the cost of extending the system to serve those customers would be too high, relative to the potential cost savings from switching to natural gas from alternative energy sources.

Of course, a portion of the system costs does vary as a function of the peak demand, and this variation is the focus of much of the engineering planning process. As a result, it is fair to say that the incremental cost of installing larger pipes or wires rather than smaller ones is a function of peak demand. And, a small portion of the costs will vary as a function of the number of customer locations (but not the number of customers, per se). For instance, the incremental cost of installing service lines to connect each customer location to the nearest distribution main or line is partly a function of the number of buildings. However, strictly speaking, even the cost of service lines does not vary directly and exclusively with the number of customers. Rather, the cost of service lines is strongly influenced by the configuration of buildings – how many buildings are served, and how far back the building is located, relative to the distribution main or line that passes by the property.

In fact, a single service line can connect a large apartment building, a quadraplex, or an individual house to the distribution system. The size and cost of the respective services may vary, but not so much due to differences in the number of residences in each building, as much as the anticipated load that will need to be handled by the service. While a larger line may be used to serve an apartment building than a duplex, the cost differences are not due to differences in the number of customers served. Neither the design of the service, nor the cost, is a simple function of the number of customers. This can easily be seen by comparing two hypothetical examples. Consider a 4,000 square foot Quadraplex and a 4,000 square foot single family home. If the anticipated electrical consumption is the same for both buildings, the cost of the electrical lines that connect these buildings to the system might be identical – yet one building could contain as many as four customers, while the other would have no more than one customer.

The central role of gas or electricity consumption, and the relative insignificance of the number of customers can be even more dramatically illustrated by considering a hypothetical building containing 30 apartments. The decision to install a service line to the building, and the size of the service line, will depend upon decisions made by the original owner or developer of the building – whether he anticipates the occupants will be using electricity for all of their energy needs, or will be using gas for some of their requirements. Suppose he decides to use electricity for everything except water heating; in that case, the developer or owner will still need to decide whether to install a centralized system that provides hot water circulating throughout the building, or install a separate water heater in each apartment, and whether to use solar, natural gas or propane to heat the water. All of these decisions will be driven by anticipations concerning energy usage over the life cycle of the investment decisions – including his perceptions concerning convenience, cost effectiveness, and other factors relating to the relative merits of each energy choice. What is striking about this hypothetical example is not only that the cost of serving the building is largely a function of decisions made based on an evaluation of the merits of natural gas or electricity relative to alternative energy sources, but also that the costs are almost entirely independent of the number of customers in the building.

The flaw in analyzing and recovering the fixed costs of the system on a per-customer basis also is vividly illustrated with another simple example. Consider a 30 unit apartment building which can be converted from individual metering to a master meter (or vice versa). While the landlord or building association may perceive an opportunity to save money by using a single meter (in order to take advantage of the volume discounts built into the Company's rates), in reality the fixed costs of connecting that building to the system may not change in the slightest – aside from the savings associated with fewer meters.

From an economic standpoint it is clear that utilities do not build a distribution system merely to meet peak demand or connect to buildings that use no energy. Rather, these investments are made in anticipation of distributing gas or electricity to those buildings. Unless this particular energy source is viewed favorably, relative to other alternatives, (<u>e.g.</u>, there is strong enough demand for natural gas), customers will not connect to the system, and ultimately the system itself would not exist.

Q. You mentioned the costs you've been discussing would be described by economists as fixed costs. Can you please explain more concerning how economists view these types of costs?

A. Yes. <u>Common costs</u> are incurred when production processes yield two or more outputs. They are often common to the entire output of the firm but can be common to just some of the outputs produced by the firm. An increase in production of any one good will tend to increase the level of common costs;

however, the increase will not necessarily be proportional. The costs of producing several products within a single firm may be less than the sum of the analogous costs that would be incurred if each of the products were produced separately.

A joint cost is a specific type of common cost--one incurred when production processes yield two or more outputs in fixed proportions. A classic example arises in the joint production of leather and beef. Although cattle feed is a necessary input for the production of both gloves and hamburgers, there is no economically meaningful way to separate out the feed costs that are required to produce each. If the quantity of leather and beef is reduced, there will be a savings in the amount of cattle feeding costs, but it is impossible to say how much of this change in cost results from the change in the quantity of leather and how much from the change in the quantity of beef.

An allocated cost is a joint or common cost that has been divided among the firm's different customers or products, in accordance with a particular formula or the judgments of a cost analyst. Economic theory demonstrates that there is no inherently correct method of allocating joint costs among the various joint products. Purchasers of each of the joint products will bear some share of the joint costs, in relative proportions that are determined by the relative strength of demand in the various markets, rather than by some arbitrary allocation formula.

Fixed costs are simply those elements of the firm's total cost which do not increase as the volume of output increases. The difference between fixed costs and sunk costs is that the former can be reduced or eliminated if the firm is willing to exit the market entirely (e.g., by converting its equipment over to another purpose). In contrast, sunk costs cannot be avoided or changed even by discontinuing production entirely; thus, they are considered irrelevant for most economic decisions. A simple example of a fixed cost is the cost of owning a factory building; as long as the building is in use as a factory, its costs are unavoidable (and they do not vary with the volume of output produced by the factory). However, if the firm discontinues production, and sells the building to someone who converts it to another use, it will avoid the costs of ownership. Hence, the cost is fixed, but it is not sunk because the building can be readily converted to another purpose.

A simple example of a sunk cost is the cost of writing a novel. Once this cost is incurred, it cannot be avoided, reduced, or eliminated, regardless of whether or not the novel is published, or how many copies are sold. Stated another way, sunk costs are irretrievable once the decision to incur them is implemented. From that time forward, they are completely irrelevant to any pricing, production, or other economic decisions that must be made.

Q. How do these concepts relate to the issues in this proceeding?

A. In attempting to analyze prices relative to costs, joint costs create considerable difficulty and controversy. The classic solution favored in regulatory proceedings is to allocate a reasonable share of the joint costs to each of the joint products. Unfortunately, as economic theory demonstrates, there is no unequivocally correct way to allocate these costs among the various services (or customer classes).

The costs of installing and operating a gas or electric distribution system are almost entirely common costs – as should be apparent from the fact that numerous customers are all served using a common system – and it is difficult to disentangle the cost of serving one customer from the cost of serving another customer. Looking more closely at the definition of common costs given earlier, it is apparent that if the volume of gas or electricity distributed to any single customer increases, to the extent this increases the overall cost of building and operating the system, the increase in total costs will not necessarily be proportional to the percentage increase in usage. Similarly, the costs of providing gas or electricity service to multiple customers (or customer classes) within a single firm will tend to be substantially less than the sum of the analogous costs that would be incurred if each customer (or customer class) were served separately. In other words, gas and electricity distribution system enjoy economies of both scale and scope.

Because of the pervasive impact of economies of scale and scope, there is no unambiguous or perfect method available for allocating the fixed costs of the distribution system – whether based on principles of "cost causation" or otherwise. The most that can be hoped for is an allocation method that produces reasonable and equitable results.

For example, in the gas industry, the cost of installing pipes is a sunk cost: once the pipe is in place, no future decision will alter those installation costs, or allow them to be not incurred. If the company is able to salvage some of the material involved, the salvageable portion of the pipe cost would be considered a fixed cost, but not a sunk cost. However, the labor needed to engineer and install the facilities is irretrievable. Therefore, once the labor costs of installation have been incurred, they are irrelevant to future decisions about the appropriate price level for the service or services that utilize the pipe (or wire).

In the calculation of marginal or incremental cost, fixed and sunk costs are canceled out in the computations. This is one of the most distinctive attributes of the economist's concept of marginal cost, setting this concept apart from more conventional notions of average or total cost. The reason for this distinctive treatment is straightforward: since fixed and sunk costs do not change with the volume of output, they have no direct impact on the level of marginal cost, which is the change in total cost associated with a change in output.

Q. Can you relate this discussion of joint and common costs to the issue of how Con Edison's fixed costs should be allocated, and whether it is reasonable to allocate many of these costs on the basis of the number of customers in each class?

A. Yes. Both gas and electric distribution systems are rife with costs that have many of the characteristics of a "joint" cost in the classic sense. To a large extent, system costs are a function of the number of miles of streets served, and not a function of the level of peak demand or the number of customers who are, or will be, connected to the system. For instance, the cost of opening a trench and installing a gas or electric distribution line of even minimum size is substantial – and this “minimum system cost” closely fits the classic definition of a “joint” cost, since it does not vary with output (e.g., the volume of energy delivered through the system), but rather with the number of miles of electric or gas distribution lines that need to be installed.

In competitive markets, to the extent common costs vary with output, they are recovered in the same manner as direct costs; they 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 thus the variability of these costs does not directly determine prices in competitive markets.

In competitive markets, joint costs are recovered through the prices charged for all of the different products or services produced through the joint production process, with the respective proportions depending upon the relative strength of demand for the various services or products. Similarly, in competitive markets different groups of consumers contribute different amounts toward the recovery of joint costs, based upon the strength of demand in different markets or submarkets. In essence, 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. Have you attempted to correct some of the problems associated with Con Edison's cost allocation approach?

A. Yes. We have developed an alternative version of the Company's gas and electric cost results that partially corrects for some of the problems we've discussed – particularly the manner in which the "minimum system" costs are allocated across classes. More specifically, we classified the minimum system costs as "Fixed Costs" rather than "Customer Costs" and we allocated these fixed costs based upon data related to the volume of energy flowing through the system. In this alternative study we accepted the Company's allocation of services across customer classes, despite various problems with this allocation, including its reliance upon very small sample sizes. However, within each class we allocated the service costs based on energy, rather than assuming the same amount should be attributed to (or recovered from) each customer, regardless of their size and usage characteristics.

Our recommended approach recognizes that the primary purpose of the system is to provide energy used by its customers, and thus it gives considerable weight to energy usage (total gas or electricity usage). As well, this approach is more consistent with the manner in which these types of fixed costs would be recovered in a competitive market – since they are "joint costs" in a competitive market scenario larger customers, who gain more value from using the system, would make a larger contribution toward recovery of these costs than smaller customers, who obtain less value from using the system.

The potential significance of different allocation methods can be seen on Exhibit ___ (URP-1). As shown, the Residential and Religious (SC 1) category has approximately 85% of the Company's electric customer accounts, and 61% of the gas customer accounts, yet this category is responsible for using just 25% of the electricity and less than 5% of the gas flowing through the Company's systems.

Q. Have you developed any estimates of the impact of following your recommendations?

A. Yes, we have. We developed some estimates of the impact of applying our recommended allocation approach, which are shown on Exhibit ___ (URP-2) and Exhibit ___ (URP-3).

For ease of development and comparison, these calculations were based on the same overall numbers initially used by the Company. Thus, for example, the overall rate of return in the electric study (10.88%) is the same figure shown in the Company's study. However, our recommended approach generates noticeably different rates of return for individual customer classes, relative to the Company's results. For example, the rate of return for Service Class 1 (Residential and Religious) is 11.43%, compared to 10.67% estimated by the Company. The rate of return for Service Class 2 (General-Small) in our study is 10.18%, compared to the 8.99% rate of return estimated by the Company for this class. The rate of return for Service Class 9 (General Large NTD) is 11.85% using our recommended approach, compared to the 12.22% shown in the Company's study. The rates of return in our study are compared to the rates of return in the Company's study on Page 1 of Exhibit ___ (URP-2).

Q. Have you prepared a similar exhibit comparing the results of your recommended allocation approach for the gas system?

A. Yes. Page 3 of Exhibit ___ (URP-2) compares the rates of return in our gas embedded cost study to the corresponding results in Con Edison's gas ECOS study. As shown, the total system rate of return is the same under both approaches (7.54%). However, using our recommended approach to allocating fixed costs, the rate of return being earned by the Residential and Religious (SC 1) class is 16.108%, compared to the Company's estimate of 6.921%. As we explained earlier, the Company's approach places too much of the cost-recovery burden on these small customers. As shown, the rates of return for the remaining gas customer classes are lower than the corresponding rates of returns developed in Con Edison's gas study. In the case of the Residential and Religious Heating (SC 3) class, the difference is very slight – 6.83% in our study and 7.00% in the Company's study.

VI. REVENUE DISTRIBUTION

Q. Please turn to the sixth section of your testimony. What factors do you think should be considered in determining how the approved rate increase should be distributed across the various classes?

A. We recommend giving substantial consideration to our recommended cost of service study results, but it is important to recognize that other factors can also be considered in developing a fair and reasonable revenue distribution, including historical rate relationships, ability to pay, relative risk, and demand or market conditions (including the extent of competition that might exist).

It is sometimes argued that the revenue burden should be distributed among the classes based entirely upon the results of one particular class cost-of-service study, at least as a goal. This argument has grown in popularity as "cost-based" ratemaking has come into vogue. However, we fundamentally disagree with this philosophy, even if the embedded cost allocation study were completely uncontroversial and flawlessly executed (which is unlikely to be the case). A reasonable cost-of-service study, like the one we have developed for use in this proceeding, can provide a useful starting point in determining the overall revenue distribution; but even if the cost study itself is not controversial, the ultimate determination of the rate spread across classes should be tempered by consideration of other factors, such as the ones we just enumerated.

Any proposal to move away from the existing rate relationships should be implemented gradually. This is particularly important in a case like the present one, where the only data submitted by the Company is for a single year (2010) and thus there is little information available to evaluate how various allocation methods react to changing weather and economic conditions. As a result, little is known about how the various class returns will react to changing conditions in the future.

More fundamentally, we believe the revenue distribution should not be designed merely to track the results of a particular cost-of-service study, regardless of how well founded that study may be. Instead, thought should be given from the outset to the potential hardships imposed on particular classes, historical relationships among the classes, and other elements of interclass equity. Moreover, the Commission should recognize that efforts to achieve perfectly uniform class rates of return are mostly fruitless. Even if a consistent ECOS methodology is employed from case to case, fluctuations in weather, economic conditions, and other variables can easily produce absolute fluctuations in the absolute class rates of return of 1%-3% or even more, defeating any such attempt at perfect uniformity. If an above-average increase is imposed in one case (because a class appears to earning less than the average return), a below-average increase may appear appropriate for that same class in the next case, simply because of fluctuations in economic conditions, weather or usage patterns – even if the underlying methodology is not changing. Of course, where changes in the costing methodology are involved, the class returns can fluctuate by even wider margins, due simply to differences in allocation techniques.

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 that very effort can potentially conflict with important policy objectives, like rate continuity, gradualism and stability.

Q. How has the Company proposed to distribute its proposed revenue increase among the various customer classes?

A. For both gas and electric services, the company began with the revenue requirement for the test year resulting from its ECOS studies. For electric services:

> The total net increased delivery revenue requirement of $364.5 million reflects the following: (1) a $298.0 million increase in T&D delivery revenues, (2) a $53.3 million increase in the MAC, and (3) a $13.2 million increase in purchased power working capital. The T&D delivery revenue increase is allocable to Con Edison customers and NYPA. The increase in the MAC revenue requirement is allocable to Con Edison full service and retail access customers. The change in purchased power working capital is allocable only to Con Edison full service customers.

(Electric Rate Panel, p. 14.)

For gas services,

> the increased delivery revenue requirement for the Rate Year, which is proposed to be obtained from firm sales and firm transportation customers in Service Classifications 1, 2, 3, 9 and 13, amounted to $25.347 million including gross receipts taxes.

(Gas Rate Panel, p. 22.)

The Electric Rate Panel (at pp. 14-15.) explained that the following steps were taken to allocate its calculated electric T&D delivery revenue increase to specific customer classes:

> (1) Con Edison and NYPA Rate Year T&D delivery revenues at the Current Rate Level were realigned to reflect the revenue adjustments based on Table 1A of the Company's 2010 ECOS study.
>
> (2) The Rate Year T&D delivery revenue increase, after excluding the component associated with the $13.2 million increase in the Purchased Power Working Capital and GRT, of $298.0 million was then allocated to Con Edison customers and NYPA, in proportion to their respective realigned Rate Year T&D delivery revenues. The revenue adjustments shown on Table 1A of the 2010 ECOS study for the Con Edison classes and NYPA were then added to the T&D delivery revenue increase allocated to each class to determine the total T&D delivery revenue increase allocated to each class.

Although Con Edison based its proposed revenue distribution on its ECOS study results, it ignored variations in the class rates of return that were relatively minor – falling within a "tolerance band" around the average rate of return. More specifically, it ignored variations in electric class rates of return that fell within a range from 9.79% to 11.97%. Similarly, it ignored variations in gas class rates of return within a range from 6.78% to 8.29%.

With respect to classes with ECOS results falling above the tolerance band, the Company proposed to move toward more uniform rates of return by shielding certain classes from paying any share of the proposed rate increase.

For example, it used its revenue surplus calculations to justify proposing a zero overall T&D delivery revenue increase for the SC 5 Rate II and SC 13 classes.

For classes with returns below the tolerance band, the Company proposes to increase rates by a larger than average amount, in order to move toward equalizing the returns. However, the Company took steps to mitigate the impact of its proposals for targeted rate increases. For example, with respect to the SC 5 Rate I class, it used the portion of the ECOS revenue deficiency to justify proposing an increase in T&D delivery rates that is 2.5 times the overall system average percentage increase. Offsetting adjustments were made to the revenue increases of other customer classes to insure recovery of the overall proposed revenue requirement. (Electric Rate Panel, pp. 15-16.) Similarly, it proposed rate increases for SC 12 Rate I and II customers that were greater than average – specifically, it developed calculations to increase rates to recover or “realign” one-third of the $5.7 million revenue deficiency it calculated in its ECOS study for the combined Rate I and II class. (Id., p. 16.)

According to the Gas Rate Panel (at pp. 22-23.), Con Edison took the following steps to allocate the increased gas revenue requirement:

> (1) Gross receipts taxes of $0.976 million were deducted from the total Rate Year increased delivery revenue requirement of $25.347 million to derive the delivery rate increase in the Rate Year of $24.371 million.
>
> (2) The SC 2H class Rate Year delivery revenue was adjusted to reflect one-third of the ECOS surplus indication.
>
> (3) The Rate Year delivery revenues for the SC 1, SC 2NH and SC 3 classes were adjusted to offset the adjustment to the SC 2H class described above. This ensures that the use of the ECOS study indications is revenue neutral to the Company. After application of this adjustment, the SC 1, SC 2 NH and SC 3 rates of return remained within the tolerance band.

(4) The Rate Year delivery revenue increase was then allocated to each class by applying the overall Rate Year base rate percentage increase to Rate Year delivery revenues as realigned for the ECOS study surplus indication and to net to zero. The Rate Year delivery revenue percentage increase of 2.5526% was developed by dividing the proposed delivery rate increase by the total Rate Year delivery revenues.

(5) Finally, we determined the total Rate Year delivery revenue increase for each class by adding the delivery revenue increase for each class, including the adjustments associated with the low income program and the ECOS study indications and adjustments described above.

Q. Can you please briefly elaborate on the “tolerance bands” mentioned above?

A. Yes. For both gas and electric services, Con Edison evaluated class revenue responsibility using the class rates of return developed in its ECOS studies relative to a ±10% tolerance band around the total system rate of return shown in the ECOS. In other words, classes were not considered to have a “surplus” or “deficient” if the class ECOS rate of return fell within this tolerance band. Classes that fall outside the 9.79% to 11.97% range (electric) or 6.78% to 8.29% range (gas) were considered to be surplus or deficient by the revenue amount necessary to bring the realized return to the upper or lower level of the tolerance band.

Q. What is your reaction to Con Edison's proposed revenue distribution?

A. While the Company's approach was rather convoluted, variations in the proposed percentage rate increases for specific classes appear to reflect the Company's general approach, which is to move towards greater conformity with its ECOS results (and, more specifically, greater uniformity in the class rates of return computed using its preferred cost allocation approach), while trying to mitigate or avoid extreme rate changes. This approach was applied at various stages of the rate development process, including developing of some individual rate elements, as explained in some of its discovery responses:

> Increasing the monthly customer charge for SC 2NH, SC 2H, and SC 3 to levels indicated by the ECOS study would have a disproportionate increase on small customers. Therefore, for SC 2NH, SC 2H, and SC 3 the customer charge is increased by a higher percentage than the class total delivery percentage increase, which is lower than what the ECOS study recommends, in an effort to move the customer charges closer to the levels indicated by the ECOS Study while taking into consideration customer bill impacts.

Exhibit ____ (URP-8), City of NY IR No. 392 (a)

And:

> A uniform percentage increase is applied to all blocks in SC 2 and SC 3 to provide a more uniform percentage increase to customers at various usage levels. If a fixed dollar per therm increase was applied to all rate blocks, customers with large usage would get a disproportionate percentage bill increase compared to customers with low usage.

(Exhibit ____ (URP-8), City of NY IR No. 395)

While we agree with the Company's intent of ameliorating, avoiding, or mitigating against extreme rate changes, we disagree with its specific proposals for three reasons. First, the Company's cost study suffers from serious deficiencies, as we discussed earlier. Because of these deficiencies, the Company's ECOS study does not provide a reasonable basis for evaluating the existing rate relationships or for developing a more appropriate revenue distribution. The specific returns earned by each of the classes depend in large part on the assumptions and allocation techniques adopted in the cost-of-service study. In some cases, a class appearing to fall within the tolerance band will fall outside the tolerance band if a different, more appropriate allocation methodology is used (or vice versa). Second, the calculations developed by the Company in its effort to move toward more uniform rates of return, while mitigating against extreme rate changes, are unnecessarily complex and convoluted. A simpler, more straightforward approach would be superior in our view. Third, the Company proposes to entirely exempt certain classes from bearing any share of the requested rate increase. In the interests of rate continuity, we believe every class should help bear at least a small share of the rate increase, even if its class rate of return falls above the tolerance band.

Q. Have you developed an alternative revenue distribution approach which you are recommending for the Commission to consider?

A. Yes. We have developed an alternative methodology which gives substantial consideration to our recommended class cost of service results while also giving considerable weight to historic rate relationships.

In order to avoid inter-class inequities, and in recognition of the fact that cost allocation studies are not perfectly precise, we agree with the Company's use of tolerance bands, and with the principle of taking other reasonable steps to insure that none of the classes receive an extremely large percentage rate increase. However, this can be accomplished in a simple, straightforward manner. More specifically, we recommend increasing the rates paid by classes with rates of return below the tolerance band by approximately two times the average percentage increase, and increasing the rates paid by classes with rates of return above the tolerance band by two-tenths the average percentage increase.

This simple approach will move the class returns toward the average, without making a futile attempt to move toward complete uniformity of returns, and without requiring any one class to absorb an inordinately large share of the revenue burden. In other words, we recommend starting with the results of our cost of service study, and looking at classes with large surpluses (outside of the Company's proposed +/- 10% tolerance band), applying a lower than average revenue increase. For classes with large deficiencies (outside of the +/- 10% band), we recommend applying a larger than average revenue increase. All of the other classes (those with a rate of return within the tolerance band) would be given a residual increase that is similar to the overall system average increase, while insuring that the overall rate increase is achieved on net balance. The exact percentages applied to the classes falling within the tolerance and will differ somewhat from the overall average, since their increases are developed on a residual basis.

Q. Can you describe a bit more specifically your recommended distribution of the Company's requested electric rate revenue requirement?

A. Yes. For electric services, the following rate schedules have returns above the upper limit of the tolerance band:

- Electric Traction TD (SC 5)
- Bulk Power TOD (SC 13)

These classes would receive a below-average increase of approximately 1.17% if the proposed revenue requirement were approved in its entirety (contrary to UIU's recommendations). Similarly, these electric rate schedules have returns below the lower limit of the tolerance band:

- Electric Traction NTD (SC 5)
- Multi-Dwelling Redistribution (SC 8)
- Multi-Dwelling Space Heating (SC 12)

They would receive a 11.69% increase if the proposed revenue requirement were approved exactly as requested (which UIU is not recommending). Finally, these electric rate schedules have returns within the +/- 10% tolerance band:

- Residential and Religious (SC 1)
- General Small (SC 2)
- Street Lighting and Signal (SC 6)
- General Large (SC 9)

These classes would be increased by the residual percentage amount needed to recover the overall requested revenue requirement, which is approximately 4.87%. For convenience, these recommendations are summarized in greater detail in the second column of Exhibit ___ (URP-4) on pages 1 and 2.

The calculations in Exhibit ___ (URP-4) through Exhibit ___ (URP-7) are strictly illustrative, intended for general comparison purposes. The actual rate changes that we recommend be applied to each class will, of course, require additional refinement, to ensure precise recovery of the actual revenue requirement determined and approved by the Commission.

Q. What about gas services?

A. In our ECOS study, the only gas rate schedule with a return above the upper limit of the tolerance band is:

- Residential and Religious (SC 1)

Under our recommended approach, this class would have their rates increased by two-tenths of the average percentage increase, which would be 0.53% if the proposed revenue requirement were approved in its entirety. Similarly, these gas rate schedules have returns below the lower limit of the tolerance band:

- General Non-Heating
- General Heating

They would receive an increase that is twice the overall average increase, or approximately 5.85% if the proposed revenue requirement were approved exactly as requested. The remaining classes – Residential and Religious Heating (SC 3) and Seasonal Off-Peak Firm Sales (SC13) – would receive a residual rate increase in order to recover the remainder of the overall requested revenue requirement, which we estimate would work out to approximately 2.55%, as shown on pages 3 and 4 of Exhibit ___ (URP-4).

VII. CUSTOMER CHARGES, MINIMUM MONTHLY CHARGES AND DECLINING BLOCK RATES

Q. Can you briefly describe Con Edison's approach to electric customer charges and gas minimum charges?

A. Yes. With regard to the customer charges in its electric rates, the Electric Rate Panel (at pp. 32-33) stated:

> The customer charges in SC 1 Residential and Religious (Rate I), SC 2 General Small (Rate I), and SC 6 Public and Private Street Lighting were increased to better reflect the Company's cost to provide service. For SC 1 customers taking service under the low-income customer rate program, the customer charge was reduced by $8.50 per month from the otherwise applicable SC 1 customer charge.

Similarly, with regard to the minimum charges in its gas rates, the Gas Rate Panel (at pp. 29-30) stated:

> The minimum charge in each service classification, which includes delivery of the first three therms of gas, was increased to better reflect the indications of the ECOS study. In SC 1, the minimum charge was increased from $18.60 to $19.25. The minimum charge for SC 2H was increased from $30.45 to $33.00, and the minimum charge for SC 2NH was also increased from $30.45 to $33.00. The minimum charge for SC 3 was increased from $20.40 to $22.00. The SC 13 minimum charge, which is based upon the minimum charge for SC 2NH, and which is designed to collect minimum

charges over seven months rather than 12 months, was increased from $52.20 to $56.57.

All of these numbers, and the approach taken by the Company in developing this part of its rate design, is a direct continuation of Con Edison's claims that many of its fixed costs should be classified as “customer costs” and recovered on a per-customer basis. Essentially, the Company is arguing that since these parts of its distribution systems are fixed (not varying with the volume of gas or electricity that moves through the system or the peak rate of energy usage), the costs should be attributed to the “customer” category and recovered on a uniform per-customer basis.

As should be apparent from the earlier discussion, we does not agree with that reasoning or that conclusion. We does not dispute that many of the costs of a natural gas or electric distribution system are fixed (or sunk, once the investment is made), but even when one takes a long run view of these costs, they do not actually vary with the number of customers. Even during the planning phase, before investments are made, it's apparent that most of these costs are actually determined by the configuration of the road network, the positioning of buildings relative to that network, the size of the buildings, and various other factors that are not directly tied to the number of customers that are, or will be, located in those buildings or served by the system.

Q. Do you agree with Con Edison's customer charge and minimum gas charge proposals?

A. No. Once the joint costs of the minimum system and services are removed from the customer cost analysis, it becomes apparent that many of these rates are already higher than necessary or appropriate. No further increases in these rate elements are warranted, and it would be preferable to gradually shift away from this revenue source toward higher kWh and therm rates.

When customer charges are set at reasonable levels, they are an acceptable rate-design tool for recovering a portion of a regulated utility's costs. However, the Company's proposed customer charges and minimum bill amounts are already higher than necessary. Further increases in these rates are not necessary, nor are they justified by cost considerations, and in our view it would be more consistent with such important policy objectives as economic efficiency, energy conservation, and inter-customer equity to moderately reduce these rates.

If Con Edison's line of reasoning were fully accepted , one could argue for virtually eliminating energy charges (aside from passing through the cost of purchased energy), and in favor of charging all of the customers in any given class roughly the same amount per month towards recovery of the fixed costs of the system – regardless of whether the customer only uses energy delivered through the system for cooking, of whether they also use it for water heating, or for many other purposes (e.g., heating).

Similarly, if this flawed line of reasoning were accepted and taken to its logical conclusion, the Company could charge the same price per month to deliver gas or electricity to a small studio apartment in the Bronx, or to a luxurious six bedroom penthouse apartment or town house on the Upper East Side in Manhattan. In fact, if this same flawed logic were taken to its extreme, it could even be used to justify recovering roughly the same amount of fixed distribution costs from a small deli as is recovered from a large grocery store, or a 40-story office building that uses a hundred or a thousand times more energy than the deli – assuming the deli, the grocery store and the office building are each served on a single customer account, billed through a single meter.

Admittedly, in this proceeding Con Edison is not taking this flawed approach all the way to its logical conclusion. For instance, the Company made an effort to analyze some of its Service costs in way that recognizes some of the differences that exist between the cost of serving residential customers in large apartment buildings and single family homes. However, those attempts were inadequate, and there are other places in its studies where it fails to recognize the extent to which different size customers incur different costs. For instance, a small deli will probably receive energy through a service that is shared with a various other small tenants in the same building, a large grocery store will more than likely use a service that is not shared with any other customers – something that is not adequately considered in the Company's analysis of commercial service costs.

It's also worth noting that the Company is not proposing to increase its electric customer charges and minimum gas charges to the full extent of the supposed customer costs developed in its ECOS studies. For example, with regard to gas, the Gas Rate Panel (at p. 30) explained:

> As reflected in the gas ECOS study, the SC 2 and SC 3 average customer costs range from $84.07 to $99.45. Given the disparity between minimum charge indications at embedded costs and the minimum charges included in current rates, the proposed increases make additional progress in moving these minimum charges toward their indicated cost of service while limiting customer bill impacts.

Q. Aside from your disagreement with Con Edison's customer cost analysis, do you have any other reasons for disagreeing with its electric customer charge and minimum gas charge proposals?

A. Yes, we do. There are several additional problems with the Company's proposals. First, holding all else constant, higher customer charges and minimum charges tend to encourage more energy consumption and discourage energy conservation; lower minimum bills and customer charges tend to discourage energy usage and reward efforts to achieve greater energy efficiency.

Second, higher minimum bills and customer changes tend to place a heavier burden on low use customers, for whom this is a major element of their electric or gas bill, including those who do not own a large number of appliances, those who set the thermostat at a high level during the summer or at a low level in the winter – or find other ways to use relatively little gas or electricity. It is not logical, equitable, or economically efficient to demand that a low use customers pay the same amount per month toward fixed costs as high use customers, who get much greater benefit from the system. The illogic of the Company's position would have been self-evident if they had taken their reasoning to its logical extreme, and argued that a customer living in a small studio apartment in Queens should pay the exact same amount per month for use of the distribution system as someone living in a 6,000 square foot penthouse apartment in Manhattan.

Q. Would you elaborate on your first point?

A. Yes. Customer charges have a negative effect similar to that of declining block rates, in which the effective price per unit drops as the level of usage increases. In general, such rate structures make small-volume users pay a higher average rate per kWh or therm for the use of the system than large-volume users, and they tend to confront customers with a relatively low per-kWh or per-therm rate for increased usage. This has several undesirable effects: it fails to reward low-volume users for their efforts at limiting their energy usage, and it tends to discourage customers from upgrading to more energy-efficient appliances, or taking other steps to conserve energy. Simply stated, a high customer charge or minimum bill translates into relatively low energy rates; as a result, this type of rate design sends price signals that make it appear less costly to consume additional energy, and offers relatively little reward for those customers who buy more efficient light bulbs or appliances, install additional insulation, adjust the thermostat to higher levels in the summer or lower levels in the winter, or take other steps in an effort to reduce their energy consumption.

In essence, a high customer charge or minimum bill creates an effective discount on the average rate per therm paid by large-volume users relative to the rate paid by low volume users, and it confronts customers with a marginal price which is lower than would be the case if a lower customer charge or minimum charge were adopted. In our view, this runs directly counter to the public policy goal of encouraging energy conservation, and this disadvantage alone is sufficient to outweigh any putative benefit from better tracking Con Edison's view of the best way to allocate fixed costs.

Q. Can you please elaborate on the costs that you believe are appropriately recovered through a fixed monthly fee?

A. We believe the most meaningful definition of customer costs for pricing purposes is a narrow one. Preferably, a customer charge should only include those costs which are closely related to the number of customers served each month, so that the customer charge would be closely tied to the actual cost savings realized when a customer joins or leaves the system. This approach is economically sound, it avoids the imposition of excessive burdens on low-volume customers, and it tends to encourage energy conservation.

This recommendation entails a relatively narrow definition of customers costs. Specifically, we believe that only accounts 901-903 and possibly 586, 905, and 907-910 should be included in the calculation of the fixed monthly rate element (customer charge). This closely matches the costs which are directly related to a customer's Con Edison to join or leave the system and which therefore are most appropriate to recover through a fixed monthly fee which is incurred when a customer joins the system, and which can only be avoided if the customer leaves the system.

Q. To the extent they are not recovered through a fixed monthly fee, how should Con Edison recover the fixed costs that it classifies as “customer costs”?

A. In our opinion, these fixed costs are most appropriately recovered in the same way that most unregulated businesses most often recover these sorts of overhead costs--through payments that are closely related to the value received from the joint production process that gives rise to these types of fixed costs. Most competitive firms do not charge a monthly fee or send a minimum monthly bill just for the right to be a customer. Instead, by far the most common practice is to build their fixed overhead costs into the prices of the various goods and services they sell.

For instance, a retailer typically recovers overhead costs from his retail mark-up, not from a flat monthly fee charged customers for the right to shop in the store, or a per-visit fee incurred each time someone walks through the door. Similarly, customers generally do not pay a fixed monthly fee for the right to buy a car when they need one. All of the auto manufacturers' and auto dealers' overhead costs are recovered in the price of the cars actually sold to customers. Even book and music clubs recover most of their overhead costs through actual sales transactions – despite the fact that these firms incur additional costs with every additional customer who joins or stays on their system. The fixed costs of maintaining customer accounting records and sending monthly mailings to each customer are normally recovered strictly on the basis of the books, and music that is actually purchased – rather than a flat fee imposed on customers regardless of how little or how much benefit they gain from the service.

Let us hasten to add that there are exceptions – special situations where competitive firms impose fixed monthly or annual charges regardless of actual purchases. For instance, some credit card companies impose a fixed annual fee on some of their card offerings. But, such charges are relatively rare in unregulated markets, even for firms with relatively high levels of fixed costs in comparison to their variable costs. For instance, airports and airlines both have substantial fixed costs unrelated to the number of customers who fly. Even though it might be feasible, they do not assess a flat fee to every person who enters the airport in order to recover those costs. Nor do airports or airlines charge a fixed fee for the right to fly, regardless of whether or not a person chooses to fly during a particular month. Instead, these fixed overhead costs are recovered as and when tickets are sold.

In all of these examples from unregulated markets, the key point is that customers who buy more of the firm's goods and services pay a higher portion of the firm's fixed overhead costs than customers who buy less. But, since larger customers also receive a proportionately greater benefit, no one complains that it's unfair or unreasonable for them to contribute more toward the firm's fixed costs. Applying the same logic to the pricing policies of gas and electric utilities, it is reasonable to recover most overhead costs through the variable rates charged for using the system. This pricing method tends to recover fixed costs from customers roughly in proportion to their actual consumption of energy, which we believe is appropriate and consistent with standard practice in most competitive markets – particularly when applied to similarly situated customers (e.g., within the residential class or within the commercial class).

The reason customer charges or equivalent flat monthly fees rarely survive in competitive markets is clear: customers tend to find them objectionable, because they are not directly associated with the benefits they receive when the service is actually rendered. Unlike regulated utilities, none of the other entities just discussed (retail stores, gas stations, book clubs, and airlines) have sufficient monopoly power to impose this non-intuitive and potentially inequitable form of pricing on their customers. Hence, in most unregulated markets normal market forces lead firms to recover their fixed costs in the price of the goods and services actually consumed--even though the underlying costs do not vary directly with sales volume and even though some of the costs in question may vary to a degree with the number of customers.

Q. Are you able more specific in your recommendations concerning customer charges and minimum charges in this proceeding?

A. Yes. At a minimum, we recommend the Commission not increase these rates in this proceeding, since these rates are already at relatively high levels, and it would advance the public interest to recover more of the Company's fixed costs through volumetric charges – which will encourage energy conservation and be more consistent with the analogous pricing patterns observed in most unregulated markets.

Going one step further, we recommend the Commission modestly lower Con Edison's customer charges, particularly if the overall revenue increase approved by the Commission is lower than requested by the Company, which would insure that this can be accomplished without imposing an excessive percentage increase on the bills of larger customers. This would be a further step in the direction established in the previous case, when declining block rates were eliminated. In Exhibit ___ (URP-5) and Exhibit ___ (URP-6) we developed some rates that illustrate the approach we recommend be adopted by the Commission, albeit using the Company's requested revenue requirement. We also estimated the impact of these illustrative rates on typical bills, in Exhibit ___ (URP-7).

Q. Let's turn now to declining block rates. Can you begin by briefly describing this rate structure?

A. Yes. Declining block rates apply incrementally lower prices as usage increases. For example, a gas customer might incur a charge of $1.00 per therm for the first block of consumption (e.g., first 10 therms); a rate of $0.60 for the next block (e.g., the next 20 therms); and a rate of $0.40 for all therms above that.

Q. Did the Commission address declining block rates in the Company's most recent rate case?

A. Yes. The Joint Proposal approved by the Commission in the Company's prior electric rate case had certain provisions related to declining block rates. Specifically,

> [C]onventional declining block rate structure in SC 1 (residential), SC 2 (small commercial), SC 7 (residential space heating), the redesigned SC 4/9, SC 8 (residential multiple dwelling redistribution) and SC 12 (residential multiple dwelling with space heating) will be replaced with a flat rate structure that will be phased in over a four- to five-year period, depending upon the service class (i.e., extending one or two years beyond the term of this rate plan).

(March 26, 2010 Order, Case 09-E-0428, p. 17.)

The Commission concluded:

> We find that the movement away from declining block rates to a flat rate structure is compatible and consistent with the

> State and Commission long-term energy efficiency policy to reduce electricity usage by 15% statewide by 2015. Eliminating the declining block structure supports this energy policy by removing the economic disincentive for customers to conserve energy.

(Id.)

Q. What is the Company proposing regarding block rates in this proceeding?

A. The Company is following the Commission's order by phasing out declining block rates in its electric tariffs. The Electric Rate Panel (at pp. 5-6) simply stated:

> In this testimony, we use "Current Rate Level" and "Current Rates" to describe rates and revenue levels associated with the rates that became effective April 1, 2012, including revenue neutral changes associated with the elimination of the declining block rate in SC 1 and phase out of declining block rates in SCs 2 and 9 that will become effective April 1, 2013 as directed by the Commission in its Order Establishing Three-Year Electric Rate Plan.

With respect to gas rates, the Company's Gas Rate Panel (at pp. 30-33) described Con Edison's proposed changes in this way:

> After considering the amount of the delivery revenue increase attributable to increases in the minimum charges, the remaining non-competitive delivery revenue increase within each class was allocated as follows:
>
> - The charge for the remaining rate block for SC 1 (for all usage over 3 therms per month) was designed to collect the balance of the revenue increase assigned to SC 1.
>
> - The charges for the remaining three rate blocks within SC 2 and SC 3 (for usage between 4 and 90 therms, for usage between 90 and 3,000 therms and for usage greater than 3,000 therms) were increased, on a uniform percentage basis, based upon each class's remaining revenue increase after deducting the increase in annual revenues attributable to each class's minimum charge and to the air conditioning rates (as explained below).

- After accounting for the increased revenues to be collected through the SC 13 minimum charge, the two remaining SC 13 rate blocks were assigned the balance of the rate increase assigned to SC 13 on an equal percentage basis. Consistent with our current rate design, the SC 2 and SC 3 air-conditioning rates were set equal to the proposed block rates in SC 13, because the air-conditioning rates apply to seasonal off-peak firm gas usage, as SC 13 rates do.

- Consistent with current rate design, Rider D (Excelsior Jobs Program) and Rider G (Economic Development Zone) rates were set equal to the applicable SC 2 rates for the first 250 therms per month of usage. The delivery rates for usage in excess of 3,000 therms (the "terminal rate") were set at 50% of the corresponding SC 2 delivery rates. The rates for usage between 250-3,000 therms (the "penultimate rate") were set at the increased terminal rates plus the difference between the proposed SC 2 terminal rates and the proposed SC 2 penultimate rates, thereby maintaining the existing differential between the SC 2 penultimate and terminal rates.

As should be apparent from these lengthy excerpts, the Company's testimony does not discuss or defend the declining block rate structure in its existing gas rate design, nor has the Company proposed to flatten its gas rates in order to phase out, or move away from, its declining block rate structure.

Q. Do you agree with the Company's approach to volumetric block rates?

A. No. In the case of electrical services, the Company is doing what has previously been ordered by the Commission; phasing out its declining block rates, but it goes no further. In the case of gas service, Con Edison does not appear to be making any effort to flatten its rate design or move towards more uniform rates.

Q. Would it be in the public interest to gradually move gas rates in the direction of greater uniformity?

A. Yes. For essentially the same reasons we offered in the context of our discussion of Con Edison's customer charges and minimum gas charges, we believe a greater share of the fixed costs of the system should be recovered from larger users, and that rates should provide a greater incentive for customers to conserve energy. Declining block rates tend to discourage (or at least not encourage) energy conservation. As the Commission noted in Con Edison's previous electric rate case, eliminating declining block rates removes the economic disincentive for customers to conserve energy, and it strengthens the incentives for customers to invest in more energy efficient appliances, add insulation, adjust thermostats, and take other steps to use less energy. The reasoning holds true for both gas and electric services.

In general, declining block rates place a heavier burden on low use customers, including those who own few appliances, set their thermostat at a high level during the summer or at a low level in the winter – or find other ways to use relatively little gas or electricity. Declining block rates also fail to reward low-volume users for their efforts at limiting their energy usage, and tend to discourage customers from upgrading to more energy-efficient appliances, or taking other steps to conserve energy, and they send price signals that make it appear less costly to consume additional energy.

Q. What do you recommend the Commission do with regard to the Company's block rates structure?

A. For electric services, we recommend the Commission continue on the path of phasing out the existing declining block rates and, where feasible, move toward modestly inclining block rates (with higher rates in the final block of usage). All else equal, inclining block rates tend to have the opposite effect of declining block rates; they discourage additional demand and encourage customers to take steps toward greater energy efficiency.

For gas services, we recommend the Commission begin flattening the existing declining block rates, similar to what the Commission approved in the last rate case with respect to phasing out declining block electric rates.

VIII. MISCELLANEOUS ISSUES

A. Residential Voluntary Time-Of-Use Rates

Q. Please turn to the next section of your testimony. What is the first miscellaneous issue you would like to discuss?

A. I would like to discuss Con Edison's proposals regarding its Residential voluntary time-of-use ("VTOU," also referred to as "time-of-day") rates. As the name implies, these rates vary according to the time of day the energy is being used. For instance, the price per kWh might be 2 cents during the late night hours and 12 cents during the day. This example is the simplest form of time-of-day rates. More complicated variations have multiple time categories with different rates for each category, and rate variations applicable to holidays and weekends.

Q. What is the theory behind time-of-use pricing?

A. It is widely recognized that the cost of producing electricity varies from hour to hour. This conclusion holds true under virtually any method of calculating costs. The marginal cost of producing electricity varies widely, depending upon the total load and the particular generating units used to serve this load. The theory behind time-of-use rates is simply to vary the price of electricity in accordance with fluctuations in production costs. When the cost of production is high, the price should also be high. Conversely, when the cost of production is low, the price should be low. Well designed time-of-use pricing can be thought of as a special case of marginal cost pricing. Since marginal cost theory suggests that prices should be equal to marginal costs, and marginal costs vary from hour to hour, the price of electricity should logically vary from hour to hour.

The efficiency advantages of such a pricing system are readily apparent. For example, if additional electricity costs 20 cents per kWh at a particular moment, it is hardly efficient to charge just 3 cents per kWh. If the utility charged the higher amount, some (perhaps many) customers would cut down on their usage of electricity by adjusting thermostats, turning off lights, and the like. Obviously, for these "flexible" or "adjustable" uses, customers are willing to pay the lower amount of 3 cents per kWh, but not 20 cents. Yet for every kWh which is eliminated, the utility's costs will be reduced by 20 cents. The typical situation with uniform rates is economically inefficient; the utility spends 20 cents per kWh to produce electricity which is worth far less to its customers. If the utility charged a price equal to the marginal cost of producing electricity, consumers would continue only those uses which were worth as much as the cost of producing the electricity.

The equity advantages of well designed time-of-use prices are also apparent. To illustrate, there are two customers who are the same in every way except for their consumption patterns. The first customer uses most of their electricity late at night when the marginal costs of production are very low, like 1 cent per kWh; the second customer only uses electricity at the peak usage hours of the day when the marginal costs of production are very high, like 20 cents per kWh. Given their usage, it is hardly fair to charge them same uniform price. Under a time-of-use pricing system, this inequity can be corrected because the nocturnal user is charged less than the peak-time consumer.

Q. Does the Company currently offer time-of-use rates to residential customers?

A. Yes. In one form or another, voluntary time of use rates have been part of the Company's offerings for Residential customers since at least 1997. Con Edison's current residential VTOU are in Tariff PSC NO. 10-Electricity, Leaf 397; Service Classification NO. 1-Rate II. The rates include a monthly Customer Charge, and Energy Delivery Charges that vary by time-of-day.

Q. What is the Company proposing to do regarding the current time-of-use rates?

A. With regard to pricing, Con Edison explains:

> The customer charges applicable to voluntary TOD rates for SCs 1 and 2 (Rate II) have been set equal to the Rate I customer charges of SCs 1 and 2, respectively, plus the incremental cost associated with a TOD meter. (Electric Rate Panel, p. 33) Consistent with past practice, voluntary TOD rates for SCs 1 and 2 (Rate II) were designed to recover each class's overall T&D delivery revenue requirement. The rates have been designed to be revenue neutral, i.e. the rates yield the same level of service class revenues that the Company would receive under the proposed conventional rates. After accounting for the change in the SC 1 Rate II and SC 2 Rate II customer charges, the per-kWh charges for these classes were designed to recover the balance of their residual revenue requirement.

(Electric Rate Panel, pp. 33-34.)

At a later point in its testimony, the Electric Rate Panel stated that it wants to stop accepting applications for customers to pay these voluntary rates after December 31, 2013, and that "customers on the existing SC1 VTOU rate will be grandfathered." (Id., p. 43.) During the grandfathering period (prior to eliminating the existing SC1 VTOU rate), existing customers on that rate would have the option to transfer to the new VTOU rate, but they would not have the option of returning to the existing rate. (Id.)

Q. How do Con Edison's proposed residential VTOU rates compare with the existing rates?

A. The Company is proposing to increase the VTOU kWh rates by a higher percentage than the regular Residential rates. It does not provide any justification for this realignment, apart from the cryptic explanation quoted earlier, which claims its proposals in this case are “consistent with past practice” and designed to be “revenue neutral.” Regardless of what is meant by those phrases, the effect is to increase the VTOU rates for high usage customers relative to the regular flat rates. In this regard, it is important to realize the existing rates are currently attracting relatively few customers – about one-tenth of 1% of the Company's Residential customers are currently on this voluntary rate, and these customers use significantly more electricity than the average Residential customer.

The table below compares existing residential VTOU rates with the VTOU rates Con Edison has proposed to grandfather in this proceeding. Customer charges are monthly. Delivery Charges are per-kWh.

	Current	**Proposed**	**% Change**
Customer Charge	$ 24.30	$ 21.49	-11.56%
DELIVERY Charges: June through September			
On-peak	$ 0.3027	$ 0.3642	20.32%
Off-Peak	$ 0.0116	$ 0.0140	20.69%
DELIVERY Charges: All other months			
On-peak	$0.1098	$ 0.1321	20.31%
Off-Peak	$0.0116	$ 0.0140	20.69%

Q. Has Con Edison provided evidence that the current VTOU kWh rates are too low, or that they should be increased relative to the regular kWh rates?

A. No. Perhaps this aspect of the Company's proposals relate to its request to grandfather the VTOU rate – by increasing the kWh rates, the existing high usage customers will be encouraged to switch to the new VTOU plan or the regular flat rate. Regardless, the Company has provided virtually no evidence regarding the actual costs of serving these high usage customers compared to high usage customers on the regular flat rate, nor has it explained why it wants to close the existing rate to new customers.

The Company did provide some testimony concerning peak loads in certain parts of its distribution network, and the timing of SC 1 class peaks (which apparently have been observed in the late evening hours, at a time when the rest of the system is generally well below its daily peak). While these factors might provide a rationale for adjusting the time blocks in the VTOU rate, they do not provide a valid basis for increasing the VTOU per-kWh rates relative to the regular per-kWh rates, or for grandfathering the existing rate plan.

Q. Please comment further on Con Edison's proposal for increasing the VTOU kWh rates relative to the regular per-kWh rates.

A. Yes. The Company is proposing to increase per kWh rates that are paid by less than one-tenth of 1% of its Residential customers based upon a hypothetical assumption as if the other 99.9% of the Residential customers were also billed on this rate plan (plus the cost of a VTOU meter). It refers to these as “revenue neutral” calculations, but they are completely unrealistic. Among other problems, the calculations fail to consider changes to usage which would occur if the other 99.9% of the customers were billed on a time of use basis. Nor has the

Company provided any data concerning the usage characteristics of the customers who are actually billed on this rate plan compare to 99.9% of customers who are not billed under this rate.

Perhaps the actual customers on this voluntary rate spend less time at home during the day, or have other atypical usage patterns that make them less costly to serve than customers on the regular rate plan. Common sense suggests that the customers who have voluntarily accepted billing under the VTOU rate are likely to have greater than average off-peak usage (or less than average on-peak usage), and thus are likely to be less costly to serve than the average customer of equivalent size. To the extent this is the case, “revenue neutral” calculations are inappropriate, since they assume these customers are identical to the average customer except for having a more costly meter.

Finally, we would note there is an inherent flaw to using “revenue neutral” pricing of Con Edison's VTOU services. Since off-peak rates are intentionally set lower than peak rates, if customers switch to a VTOU rate they have an incentive to alter their usage patterns in an effort to offset the higher cost of metering and to respond to the lower off-peak rate. As customers respond to these incentives and price signals, they will begin to shift more and more energy consumption from peak hours to off-peak hours. This will lead to lower bills and less revenue coming from these customers, but under “revenue neutrality,” this shift in usage would lead to increasing rates in order to compensate for the lost revenues. This would be neither equitable nor logical, since the “revenue neutral” calculations ignore the offsetting cost savings Con Edison experiences as customers move usage off peak.

Q. You mentioned that the Company has proposed a new VTOU pricing plan. Would you elaborate on that?

A. Yes. Con Edison has proposed a new VTOU plan in SC1 which is “intended to promote off-peak charging of plug-in electric vehicles ('PEV').” (Id., p. 9.) As such, it appears to be targeted at a different market niche than the one served by the existing VTOU rate we have been discussing up to this point. The Electric Rate Panel (at 38-39) stated:

> The proposed SC 1 Rate III is designed to encourage the shifting of residential usage away from both supply and delivery peak periods. By offering attractive off-peak supply and delivery rates, particularly during the summer, it also encourages SC 1 customers who have a plug-in electric vehicle (“PEV”) to engage in vehicle-charging at their residence during those off-peak hours.

The table below shows the time periods for the proposed new SC 1 Rate III VTOU rate.

	On-Peak	**Super-Peak**	**Off-Peak**
SUPPLY			
Summer	7 am to 2 pm, and 6 pm to 1 am	M-F, 2 pm to 6 pm	1 am to 7 am
Non-summer	7 am to 1am	N/A	1 am to 7 am
DELIVERY			
All year	7 am to 1am	N/A	1 am to 7 am

The customer charge would be set equal to the existing customer charge in Rate I of SC-1, plus an incremental meter charge “for a meter upgrade to accommodate time-of-use pricing.” (Id., p. 42.)

Q. How did the Company decide on these particular time periods?

A. The Electric Rate Panel (at 41-42) explained:

> The Company has set the on-peak period for supply based on an examination of system load shapes for the past five years as well as its reasonableness in the context of a thirty-year analysis of system peaks....
>
> Recognizing the goals of avoiding incremental capacity expansion and maintaining network reliability, the Company analyzed the on-peak period for the delivery system based on peak demand data for area substations. These substations may serve loads on one or more networks. The Company also analyzed peak-day usage for various-sized SC 1 residential customers. The analysis showed that peaks occurred between 8 PM and 11 PM, with the SC 1 class peak occurring at 9:30 PM.

Q. What is your response to the Company's new residential VTOU proposal?

A. We have no objection to offering residential customers more TOU rate options, or with providing them with more nuanced price signals that are appropriately tailored to actual load conditions. Given the nature of the Company's service area, we are a little skeptical about how much potential exists for the intended target market (electric car owners), but that does not mean we are opposed to designing a rate that's designed to appeal to these potential customers. We also have no strong objections to the proposed rate design – but we think it would be preferable to offer the off peak rate for a bit longer period to insure that there is ample time to fully recharge the car's batteries each night. In that regard, we think the rate would be more appealing if the off peak period ran from midnight to 7 am, rather than from 1 am until 7am.

We also have no objections, in principle, to setting higher rates during the hours in which costs are highest, which is apparently the intent of the “super peak” rate. Rates that provide an incentive to trim usage during the costly peak hours, or to shift usage from high to low cost time periods are in the public interest, and should be encouraged. In this regard, the Company's “super-peak” proposal appears to have some merit, since it offers customers a way of reducing costs to the extent they are willing and able to reduce usage during a small number of hours during the summer, when energy supply costs tend to be particularly high. To the extent some customers are willing to reduce their usage during these hours, society will benefit from avoiding the unusually high costs of generating and transmitting electricity during these hours. It is economically efficient to provide customers with price signals that are consistent with actual cost patterns.

While we agree with the general philosophy behind this proposal, we are not convinced the Company is going far enough to align prices with the underlying cost patterns. In particular, we note that the proposal for "super-peak" hours is uniformly applied throughout the summer months, rather than being more narrowly focused on specific times and days when peak usage is at the highest levels, and supply costs are correspondingly at the highest levels. Given the current state of technology, it should be feasible to go further in the direction of accurate price signals which give a strong incentive to minimize usage during the specific times when supply costs are highest (e.g., unusually hot summer afternoons).

Q. Would you please elaborate on how the peak prices could be more appropriately targeted?

A. Yes. Rather than charging a higher price during every single summer weekday afternoon, regardless of how mild the weather, or ample the supply of electricity available to the system, it would be preferable to target a smaller number of hours with very high prices. This would offer the greatest possible incentive for customers to reduce their usage during the specific hours when society would gain the most from a reduction in usage. Ideally, this narrowly targeted peak price would not only be focused on a smaller number of hours per year, it would be precisely focused on the specific times when costs are highest – the particular hours each year when weather is the hottest and the system is experiencing unusually high loads, or when unusual generating and transmission capacity constraints exist, or both.

In other words, rather than charging higher prices during every single summer weekday afternoon (what the Company calls the “super peak” hours), higher prices would be applied during a smaller number of hours when a high price is most justified – what we will refer to as the “Critical Peak” hours for the sake of clarity. The actual timing of Critical Peak hours is not dependent upon the calendar, but upon actual events. The Critical Peak hours occur when there is unusually hot weather, when one or more major generating units are down for unscheduled or emergency maintenance, or for some other reason system supply costs happen to be running at unusually high levels.

To be equitable and fully effective, customers need to be informed of the “critical peak” before it occurs, so they have an opportunity to adjust their thermostats, avoid running their dishwasher or doing their laundry, turn off their water heater, and take other actions to minimize their load during the “Critical Peak” period. With today's technology, it is perfectly feasible to inform even a large number of residential customers that a Critical Peak is about to occur. Nor does it have to be costly to do this – particularly if you accept the idea that not every single customer will receive the communication that is sent out. But, if all customers on the Critical Peak pricing plan are contacted using a combination of emails, text messages and “robo-calls” (recordings sent to the customer's telephone), a very high percentage of these customers can be expected to receive advance notification of the peak period, the per-customer cost of this notification effort would be minimal, and there would be an excellent opportunity for customers to try to minimize their load during the Critical Peak hours. If successful, this effort will minimize their individual bills, and help society by avoiding the high costs (and risks of brownouts and blackouts) that occur during Critical Peak hours.

We believe that a Critical Peak pricing approach has the potential for being more popular than conventional approaches to time of use pricing, like the Company is proposing, for the simple reason that customers would be subject to the risk of sharply higher prices during a much smaller number of hours of the year. In any event, we think there is enough upside potential for this type of narrowly focused, timely price signal to make it well worth testing. A lot can be learned from trying this concept even on a small pilot basis, applied to a relatively small number of customers who volunteer to try this pricing approach.

B. ESCO Billing Data

Q. Please discuss your next miscellaneous issue. Why is UIU concerned about ESCO billing data?

A. According to the PSC's "Order Instituting Proceeding and Seeking Comments Regarding the Operation of the Retail Energy Markets in New York State," in Case 12-M-0476, issued on October 19, 2012, DPS Staff analyzed ESCO pricing and billing data from National Grid-Upstate, Con Edison, Central Hudson Gas & Electric Corporation, and National Fuel Gas. The analysis showed that many residential and small non- residential ESCO customers paid more than what they would have paid had they continued as full service utility customers. In addition, a review of a large sample of data from retail energy markets by DPS Staff suggested that many residential and small commercial gas and electric consumers have difficulty understanding and comparing utility and energy market prices.

In National Grid-Upstate's most recent rate cases (12-E-0201 and 12-G-0202), the Public Utility Law Project of New York Inc. ("PULP") presented an analysis of customer data over a 24-month period showing that most residential and small commercial retail access consumers in that utility's service territory (including a startling number of customers enrolled in the low-income program) paid more for their gas and electric energy supply from ESCOs than they would have paid had they remained full service customers (see PULP-YATES-Exhibit B (ESCO Regular Two Year Summary Data) and Exhibit B (ESCO Low Income Two Year Summary Data) in those proceedings, Unredacted Testimony of William D. Yates., August 21, 2012, http://pulpnetwork.blogspot.com/2012/09/in-ruling-issued-september-7-2012.html).

In the Company's current rate case, there is no evidence that the Company prepared any ESCO billing studies similar to and in as much detail as the studies presented in the most recent National Grid-Upstate Rate Cases (which included an analysis of two years of customer billing data) in order to determine if retail access customers in the Con Edison service territory achieved savings on their energy supply over an entire year compared to the full service utility. In addition, in the Company's response to UIU IR No. 173, the Company released customer slamming ESCO complaint reports, that is, complaints related to customers being switched to an ESCO without their authorization, which have been provided to the Commission on a monthly basis for the past four years (2009-2012). The number of monthly ESCO slamming complaints is astonishing – ranging from approximately 300 to 1,300 complaints per month. (Please note that in order not to burden the record with confidential documents already in the possession of the Commission, the Company's response to UIU IR No. 173 is not included in the set of IRs found in Exhibit ___ (URP-8).) All of this information suggests that there are many consumer-related ESCO issues that currently exist involving the transparency of the marketplace. Even though misinformation and insufficient information may exist currently, these problems have the potential to be overcome by providing consumers with better, more accurate, more easily understood information.

Approximately 900,000 gas and electric customers in the Con Edison Service Territory are currently taking supply service from ESCOs, an increase of about 700,000 customers since 2005. (See Exhibit ____ (URP-8), attachment to UIU IR No. 57.) Approximately 132,500 out of the 900,000 customers mentioned above, according to the Company's response to UIU IR No. 131, which is contained in Exhibit ____ (URP-8), are considered low income customers. The Customer Operations Panel – Electric (at page 55.) predicts the number of customer enrollments to increase to over 1,200,000 customers by 2017. Data from UIU IR No. 69 (Exhibit ____ (URP-8)) shows that over a four-year period, an increasing amount of customers taking commodity from ESCOs returned back to full service utility rates. At this time, there are no known studies researching why so many retail access customers are switching back to utility service. With the increase in ESCO customer population along with the rise of ESCO customers switching back to utility service, there is a greater need for tools which can guide these customers in making well informed decisions when selecting or deselecting an energy supply option.

Q. Does the Company currently provide a historical bill calculator on its website that would enable a customer to compare on a total basis what they would have paid had they remained with the Company versus what they paid while taking service from an ESCO?

A. No. As indicted in the Company's response to UIU IR No. 64 (Exhibit ____ (URP-8)), the Company currently does not have an online price transparency tool to help gas and electric customers compare the Company's full service rates with the rates charged by other firms.

Q. What are the incremental costs that the Company would incur and development time frame required to implement a web-based historic bill calculator on the Company's Website?

A. According to an IR response, the Company's preliminary estimated costs associate with developing a web-based historical bill calculator is between $200,000 and $300,000, with a development time of approximately eight months. (See Exhibit ____ (URP-8), UIU IR No. 64.)

Q. What is the UIU's recommendation to the Company in order to assist ESCO customers to better understand commodity prices offered?

A. The UIU believes the price information currently available to residential or small commercial customers is not informative enough to permit the typical customer to make wise decisions concerning the manner in which they acquire energy. As a start (but not the ultimate solution), the UIU recommends the Company launch a web-based historical utility bill calculator in addition to any other bill comparison tools (e.g., enhancements to the utility consolidated bill including comparative pricing information) as part of the Company's customer outreach program – one that allows each customer to compare the Company's current rates in comparison to those charged by various ESCOs, in a meaningful “apples to apples” comparison, using data from the Company's billing records reflecting the actual amount of energy used by the customer during the prior year. This proposal is similar to those contained in the recent Joint Proposal regarding National Grid-Upstate electric and gas rates (12-E-0201 and 12-G-0202) and the Fortis Acquisition of Central Hudson (12-M-0192). The online bill tool should compare what the customer would pay at the ESCO's most recent available rates to what they would pay if they remain a full service gas and/or electric service customer – calculated on a total bill basis – delivery and commodity based upon their historical energy usage over the prior year.

Due to the increasing percentage of smart phone users (see http://www.businessinsider.com/us-smartphone-market-2012-9), this online tool should also be available as a smart phone application, thereby providing consumers with a quick and simple way to obtain meaningful information based upon their individual energy consumption and billing information, and to see how the comparison varies over the course of the year, in order to assess risks associated with weather and energy market fluctuations, and to make informed decisions. When selecting an ESCO or remaining with their full service utility for energy supply, consumers should have the benefit of accurate, meaningful information. As noted previously, this is not the ultimate solution, but it would be a significant first step in the right direction.

C. Billing And Payment Processing

Q. What is the third miscellaneous issue you want to discuss?

A. We would like to discuss the Company's proposed changes to its Billing and Payment Processing Charge (“BBP”) and some related concerns. The BPP is intended to recover the costs of processing, printing and mailing customers' bill, along with the cost of processing payments. The current BPP charge is $1.04, which was set in Case 09-E-0428. (Gas Rate Panel Testimony, p. 21; Electric Rate Panel Testimony, p. 24.)

It its testimony, the Company claims the embedded cost of the BPP functions is $1.32 per bill for electric service and $1.20 per bill for gas service. (Gas Rate Panel, p. 28; Electric Rate Panel, p. 24.) On this basis, Con Edison is proposing to increase the existing rate of $1.04 to $1.20. (Gas Rate Panel, p. 21; Electric Rate Panel, p. 24.) All electric customers are subject to the BPP charge except SC9 transportation customers receiving a utility consolidated bill or marketer consolidated bill.

Q. Do all customers receive and pay their bills in the same manner, thereby incurring the same level of costs in every case?

A. No. A customer can pay their gas and electric bills in many different ways, including by using a credit card or debit card, by paying online, by making a direct payment, by mailing a check, by making a payment over the phone, and by paying in person at a walk in center, a kiosk, or by submitting payment through various authorized and unauthorized payment agents. (Exhibit ____ (URP-8), UIU IR No. 178.) It is self-evident that some of these options are less costly than others, and that not everyone mails a check. For instance, in 2012, there were approximately 2.7 million bill payment transactions made online, according to the Company in that same IR response.

Q. Are there opportunities to reduce these costs?

A. Yes. For example, the Company currently has over 1.1 million email addresses on file (Customer Operations Panel – Gas, p. 61) but it does not currently offer customers any incentive to receive their bills by email – which would save the cost of printing the bill on paper, stuffing it into an envelope and mailing it to the customer.

We also question the costs being incurred by customers who pay their bill using a credit or debit card -- payments that are processed by an outside vendor. Residential and small commercial customers who pay by credit or debit card are required to pay a vendor fee of $4.75 per transaction. (See Exhibit ____ (URP-8), UIU IR No. 180.) The current typical monthly bill for a firm sales electric residential customer using 300 kWhs is $81.64, gas heating residential customer using 113 therms is $187.68, and gas non-heating residential customer using 8 therms is $30.55. (See Exhibit ____ (URP-9), Con Edison Rate Case Technical Conference presentation, March 11, 2013, slides 72 and 73.) Using these averages for comparison, the current vendor charge is equivalent to 5.8% of a typical residential electric bill, 2.5% of a typical gas heating bill, or 15.5% of a typical gas non heating bill. Given the high volumes – in 2012, there were over 644,000 bill payment transactions made by credit or debit cards (see Exhibit ____ (URP-8), UIU IR No. 178) – and simplicity of these transactions, we question the magnitude of these vendor fees. If the current vendors are not willing to do the processing for less, it seems likely that another vendor could be found that is willing to do the work for a substantially lower fee.

Q. What are you recommending concerning the Company's proposed BPP changes?

A. There is no compelling need to increase the BPP charges at this time. At a minimum, we think the Company should first make a greater effort to minimize these costs, by encouraging customers to opt for less costly ways of receiving and paying their bills. Many customers now have an email address and could receive their bills electronically, thereby eliminating the cost of processing, printing, and mailing paper copies. Additional savings could be achieved if more customers paid their bills electronically – particularly through the most cost effective options, like automatic payments taken directly from their checking account each month. Not only would this eliminate the cost of a return envelope and postage, it would eliminate the cost of opening and processing the check.

To encourage use of the least costly options, the Company should offer discounts or other incentives to customers who opt to receive their bills electronically, as well as to those who select the most efficient, least costly payment methods. A 50 cent discount would be reasonable for those opting to receive their bills exclusively by email, and an additional discount of a similar magnitude could be offered to customers who select one of the least costly payment methods. Customer outreach to increase awareness of these less costly options can be achieved using bill stuffers, as well as by sending periodic emails to the 1.1 million email addresses already on file.

D. Automated Meter Reading Program

Q. What is the final miscellaneous issue you would like to discuss?

A. We would like to discuss Automated Meter Reading ("AMR"). The Company and Orange Rockland Utilities, Inc. were ordered by the Commission in 2006 to submit a plan for the development and deployment of an AMR system. (Order Relating to Electric and Gas Metering Services, August 1, 2006.) The Company submitted its plan on March 28, 2007. (Id.)

The Company is pursuing two different approaches to deploying AMR; these are "Saturated AMR" and "Strategic AMR." Saturated AMR involves installing AMR technology at ever meter in a large geographic area. Strategic

AMR involves selectively replacing meters at locations "where conventional meter reading yields poor results" and replacing "obsolete remote meter reading devices in locations where one or more of these meters have failed." (Electric Customer Operations Panel, pp. 16-17.)

Q. What are the estimated costs of the Company's proposed AMR initiatives?

A. Anticipated funding requirements for the continuation of Saturated AMR initiatives, which are primarily targeted at the Bronx, total $87.7 million. (Id., p. 8) Anticipated funding requirements for the Strategic AMR plans total $7.46 million. (Id.)

Q. What are the estimated savings associated with the Company's proposed AMR initiatives?

A. Con Edison expects to be able to reduce staffing as a result of its continued AMR efforts. When the Bronx East project is completed, the Company expects to eliminate 32.5 full-time equivalent ("FTE") Customer Field Representatives, 4.5 Customer Service Representative FTEs, and two supervisors. (Id., pp. 15-16.) Company Exhibit__ (CO-2) indicates that Con Edison anticipates savings of $1.5 million in 2014, and $1.9 million annually thereafter, through 2018.

Q. How will the costs of Con Edison's AMR program be recovered from ratepayers?

A. Con Edison explained in an IR response (Exhibit ____ (URP-8), UIU IR No. 40) that the costs and associated savings will be included in the electric and gas revenue requirements, and allocated to all classes of customers.

Q. How prevalent is the problem of inaccessible customer meters?

A. According to the Company’s Electric Customer Operations Panel, p. 20, there are currently 120,000 meters that could not be accessed for 120 days or more. Of these, 85% are residential, and the rest are mostly small commercial accounts. (See Exhibit ____ (URP-8), UIU IR No. 41.)

Q. What is your reaction to the Company's proposed AMR initiatives?

A. In response to Commission directives, the Company is slowly moving toward installation of ubiquitous smart meters. However, the Company has not provided evidence concerning the extent to which its efforts are optimal. We recommend the Commission require the Company to develop a plan for gathering, organizing and analyzing data concerning its experience with both the Saturated and Strategic AMR investment programs. The goal is to glean information from the efforts to date, and evaluate whether these programs should be continued at the current pace, or slowed, stopped, accelerated, or modified.

If the programs are already fully cost-effective (generating operating cost savings sufficient to fully compensate for the investment), perhaps the pace of investment should be accelerated. On the other hand, if the experience to date suggests these programs are not fully cost effective (generating savings sufficient to pay the full cost of the program), a more detailed analysis may reveal ways in which the program could be modified to increase the cost savings, ways to reduce the investment per meter, or to target the investment more effectively, in order to improve the overall cost-effectiveness of the program.

Q. Can you briefly elaborate on the type of analysis you are recommending?

A. Yes. A detailed analysis would go well beyond simply evaluating a few top-line numbers, like those offered by in the Company's testimony in this case. For instance, the cost of installing meters may differ under different circumstances – patterns that may be discernible if the Company undertakes a detailed review of the costs it has incurred in both the Saturated and Strategic AMR programs to date.

In general, the primary goal of this effort should be to determine what lessons can be learned from the AMR investment and operating experience up to this point in order to make better decisions going forward. Rather than simply continuing its existing efforts at its currently planned pace, the Company should evaluate whether to expand upon those efforts, accelerate them, or modify them – attempting to determine the optimal pace at which it should be investing in smart meters, and at what locations. As well, this analysis should consider other options, including the potential for substantially expanding the program to better position the Company for eventual deployment of a “smart grid.” While this would require additional investments, it may yield substantial additional cost savings.

Without a careful analysis of detailed data concerning the costs and savings associated with the existing programs, it is difficult for the Company or the Commission to determine whether these programs should be expanded, accelerated or modified. If there are strong indications that automated metering is not cost-justified through the savings achieved through reduced meter reading costs alone, that does not necessarily mean these programs have been a failure, or should be ended. Conceivably, the better response may be to modify the programs to improve targeting, or to deploy additional hardware and software to enable the Company to obtain more benefits from these meters. In particular, investments that allow it to collect detailed data from the meters would greatly increase the benefits which can be obtained from this investment.

Q. Can you explain how increased software and hardware investments could improve the overall cost effectiveness of the AMR programs?

A. Yes. In preparing the analysis we are recommending, the Company should evaluate the potential costs and benefits of investing in an enhanced system that enables more detailed, and/or more fully automated collection of data from the meters. A centralized data collection system could eliminate the cost of having employees drive up and down streets in company vehicles collecting data from these meters.

In a filing submitted in Case 94-E-0952 on March 28, 2007, the Company stated:

> Given Con Edison's substantial progress in implementing a Mobile AMR system in Westchester, the Companies considered how best to upgrade the functionality of that system if an AMI system were to be implemented elsewhere in the Companies' service territories. Mobile AMR of the type installed by Con Edison can theoretically migrate to "fixed network" architecture, providing a system that offers many of the functions that would be available from AMI systems having full two-way connectivity. This "virtual AMI" system solution is available from the same technology vendor selected for the original Mobile AMR system. Con Edison would establish a fixed network by installing pole-top data collectors to receive meter data frequently and return the retrieved data to the utility. This approach preserves the investment already made in the meter sets while further reducing operating costs for meter reading by avoiding the need to drive by the meters.

(Plan for Development and Deployment of Advanced Electric and Gas Metering Infrastructure, p. 8.)

In addition to this evaluation of costs and benefits, the Company should also evaluate the pros and cons of modifying the program to enable it to use the meters to provide a continuous, or periodically sampled, stream of real-time data concerning usage patterns at individual customer locations, which in turn would be a more step toward a "smart grid" approach. This is possible because, as

Con Edison stated in an IR response (Exhibit ____ (URP-8), City of NY IR No. 265, Part (a)): "The AMR meters currently in use have additional recording capabilities that can be realized if a network of data collection devices were added to collect the meter information on a more real time basis."

These enhancements would require additional investments and operating costs, which in turn could lead to hundreds of millions of dollars of cost savings, through better, more precise price signals, automatic control of individual appliances in response to local and regional peak usage patterns, and so forth. In response to discovery (see Exhibit ____ (URP-8), City of NY IR No. 265, Parts (b) and (d)), the Company did not provide an up-to-date estimate of these costs, but it indicated instead that an earlier evaluation suggested a "narrowly positive benefit cost ratio, which is heavily dependent on customer behavior."

Of course, the amount of benefits will depend on specific programmatic and deployment decisions, as well as on how effective the Company is in communicating with customers – so a narrowly positive cost-benefit ratio could turn strongly positive with sufficient investigation into "best practices" careful evaluation of the results of research conducted by other utilities, and a well executed deployment plan.

Even if it is too soon to build a "smart grid" throughout Con Edison's system, it may not be too soon to change the focus of the Saturation AMR program to encompass more than simply reduced meter reading costs. In fact, the Company has recognized (see, for instance, Exhibit ____ (URP-8), City of NY IR No. 265, Part (d)) that the Commission has encouraged utilities to pursue smart grid technology by performing Research and Development, and by conducting pilot programs to try emerging technologies on a small scale.

In a similar vein, we question whether the Company is devoting sufficient resources to its Strategic AMR program – or whether it is viewing this program too narrowly. The Company has a significant, continuing problem with inaccessible meters, including some meters that are not accessible for long periods of time. The costs associated with repeatedly trying to access these meters, sending estimated bills, eventually reconciling the bills, and having to deal with unhappy customers must be significant. Clearly, these costs could be alleviated by installing smart meters at these locations. A careful evaluation of costs and benefits is needed to judge the cost-effectiveness of the existing Strategic AMR program, and to evaluate whether this program should be expanded or accelerated.

This evaluation should include appropriate recognition of the value of information that can be obtained by deploying additional smart meters in locations outside of the existing "Saturation" areas – effectively serving as a geographically dispersed sample of customer locations that can be used for data collection and comparison with the more comprehensive, but geographically concentrated data that can be collected from customers in the Saturated AMR areas.

Earlier in our testimony, we noted the small load research sample sizes the Company relied upon in developing its ECOS studies. By expanding the Strategic AMR program and investing in additional hardware and software that allows periodic collection of detailed usage data from a reasonably large sample of smart meters installed as part of both the Saturated and Strategic AMR programs, the Company could greatly expand its load research data collection efforts. This would also allow the Company to gain valuable hands-on experience with many other aspects of state-of-the art metering – experience that could prove highly valuable if and when the Company decides, or is ordered, to move toward widespread deployment of "smart grid" systems.

We would also note that this evaluation should include appropriate recognition of the probability that a smart meter may eventually be installed at a given inaccessible location for other reasons. If a smart meter is going to be installed at a given location a few years from now as part of the Saturated AMR program, or because the existing meter will approach the end of its life cycle and need to be replaced for reliability reasons, then it would be misleading to compare the full cost of the smart meter to the savings from overcoming inaccessibility problems when evaluating the cost effectiveness of the Strategic AMR program. Instead, the relevant comparison would consider the net present value of making an investment in smart meters now, rather than a few years from now. The net present value of bringing the investment forward to an earlier time period would in turn be compared to the operational, informational and other benefits achieved during that initial time period.

Q. Does this conclude your direct testimony?

A. Yes, it does.