STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

UIU ELECTRIC RATE PANEL ON THE JOINT PROPOSAL

Dated: October 13, 2016
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, business addresses, and backgrounds?

A. **(Neal)** My name is Mary Neal. My business address is One Washington Mall, Boston, MA 02108.

Currently, I am a Senior Consultant at Daymark Energy Advisors ("Daymark"). I have been with this energy planning and regulatory economics firm for over six years. In my time at Daymark, I have provided extensive analysis of electric utility cost allocation models and assisted in analyzing electric and gas rate design in various regulatory proceedings. I was the lead consultant in creating the cost allocation model for Stowe Electric Department in Vermont Docket No. 8463 and recently built a revenue requirement and rate design model for Kauai Island Utility Cooperative's new LED streetlight rates, which were approved by the Hawaii PUC (Transmittal 2015-03). I also developed electric vehicle rates for the Village of Swanton, Vermont. Moreover, I have reviewed electric utility plans for the acquisition and building of new resources, as well as capital upgrades to existing units for utilities in four states and in two Canadian provinces. Prior to working for Daymark, I worked for Solar Turbines, Inc. for three years, designing low-emissions combustion systems for industrial gas turbine engines. I received my B.S., Mechanical Engineering in 2005 from the University of California, Davis, and my M.A., Energy and Environmental Analysis in 2010 from Boston University.

I have submitted prefiled direct and rebuttal testimony before the New York Public Service Commission ("Commission") as part of the UIU Electric Rate Panel in this proceeding, Cases 16-E-0060 *et. al* . I also presented testimony in three rate cases in Wisconsin and three proceedings in Nova Scotia regarding Nova

Scotia Power's Annual Capital Expenditure Plans. I also filed testimony in Joint Dockets 05-CE-145/05-CE-147, relating to Wisconsin Electric Power Company's application to upgrade the Elm Road Generating Station and its associated fuel handling system to accommodate increased fuel flexibility.

(Panko) My name is Danielle Panko. I currently hold the position of a Utility Analyst with the Utility Intervention Unit ("UIU") of the New York State Department of State's Division of Consumer Protection 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.

From 2000 to 2001, I served as an intern with Central Hudson Gas and Electric Corporation located in Poughkeepsie, New York, in the Accounts Service Department and subsequently in the Electrical Engineering Department. From 2004 to 2007 I worked as an engineer for Philips Semiconductors. From 2007 to 2012, I worked for Consolidated Edison Companies of New York, Inc. ("Con Edison" or "the Company") in the Rate Engineering Department as an Analyst, and later a Senior Analyst, in the Gas Rate Design Section. I joined UIU in 2012. My primary responsibilities include assisting with UIU's participation in Commission proceedings, researching utility policy and regulatory related issues, and representing UIU during various utility-related meetings and rate case negotiations. Recent electric cases that I have worked on include Cases 13-E-0030, 14-E-0318, 15-E-0283 and 15-E-0285, in addition to over a dozen other rate and policy proceedings. I previously submitted testimony in Cases 13-E-0030, 13-

G-0031, 14-E-0318, 14-G-0319, 14-E-0493, 14-G-0494, 15-E-0283, 15-G-0284, 15-E-0285, 15-G-0286, 16-G-0257, and 16-G-0058 and 16-G-0059. I also have submitted prefiled direct and rebuttal testimony as part of the UIU Electric Rate Panel and UIU Gas Rate Panel in these proceedings, Cases 16-E-0060 *et. al* .

(Smith) My name is Lee Smith. My business address is One Washington Mall, Boston, MA 02108.

I am an independent consultant working exclusively for Daymark Energy Advisors. Previously I worked as an employee of La Capra Associates, an energy planning and regulatory economics firm that is now Daymark Energy Advisors, for 28 years.

I have a B.A. in International Relations (with a minor in Economics) with honors from Brown University. I also completed all the work except for the dissertation for a Ph.D. in Economics from Tufts University. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level.

I have prepared testimony on gas and electric rates, rate adjustors, cost allocation and other issues regarding more than 40 utilities in 20 states, in Canada, for a number of municipal regulatory authorities, and before the Federal Energy Regulatory Commission. I participated in development of the New England ISO, and advised a number of clients on various aspects of electric restructuring. My clients have included public advocates, gas and electric utilities, regulatory commissions and other public bodies. I assisted in writing testimony for New York Power Authority many years ago but had not testified in New York until this case. I have submitted prefiled direct and rebuttal testimony as part of the UIU Electric Rate Panel in this proceeding, Cases 16-E-0060 *et. al* .

Q. Please summarize Daymark and its business.

A. Daymark Energy Advisors provides consulting services in energy planning, market analysis, and regulatory policy in the electricity and natural gas industries. We serve clients throughout North America from our offices in Boston, Massachusetts, and Portland, Maine, providing consulting services to a broad range of organizations involved with energy markets, including public and private utilities, energy producers and traders, financial institutions and investors, consumers, regulatory agencies, and public policy and energy research organizations. Our technical skills include power market forecasting models and methods, economics, management, planning, rates and pricing, and energy procurement, and contracting. Over the past several years, our firm has been very active in electric industry planning issues, including integrated resource planning, transmission planning, wholesale and retail market analysis, competitive bidding and procurement, and renewable energy.

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

A. Yes, Exhibit ___ (UERP–JP-1) through Exhibit ___ (UERP–JP-10) accompany our testimony. All of these exhibits were prepared by us or under our supervision.

Q. Has the panel requested additional information from the Company to assist in preparing this testimony?

A. Yes the panel has sent information requests and received responses from the Company explained in further detail below. UIU Information Requests 261 and 263 each address questions regarding the use of DC power in the Company service territory. (Exhibit___(UERP-JP-6) UIU-19-263 and UIU-19-261). The panel is also familiar with the Company Response to UIU Information Request 260 which addresses the conditions under which the Company replaces a 1.0 Awg OH conductor. (Exhibit___(UERP-JP-6) UIU-19-260.) In UIU Information Request 209, UIU asked questions regarding underground transformers and data contained in prefiled Company Exhibit DAC-2 Schedule 1 (Confidential), tab 2013 UG Transformers. (Exhibit___(UERP-JP-6) UIU-10-209.) Additionally, in UIU Information Request 207, UIU asked questions regarding overhead transformers and data contained in Exhibit DAC-2 Schedule 1 (Confidential), tab 2013 OH Transformers. (Exhibit___(UERP-JP-6) UIU-10-207.) In addition, in response to UIU Information Request 268, Company provides information regarding a "typical" transformer serving 6 customers. (Exhibit___(UERP-JP-6) UIU-10-268.) In response to UIU Information Request 241, Company provides limited information on what components of distribution plant were planned to meet the ICMDs of multifamily dwelling units. (Exhibit___(UERP-JP-6) UIU-15-241 which refers to Company Response to UIU 150 Exhibit___(UERP-JP-6) UIU-8-150.) In response to UIU Information Request 18-257, Company provided a Commonwealth Edison Company report entitled "Survey of Approaches to Distribution Cost Allocation by Voltage" (October 28, 2011).

Q. What is the nature of this testimony?

A. We will focus on some key aspects of the rate and tariff changes contained in the Joint Proposal filed in these proceedings on September 20, 2016 ("JP"). These aspects include the portions of the JP that adopt the Company's electric embedded cost of service ("ECOS") study, revenue allocation methodology, various aspects of the Company's rate design, and a few other miscellaneous issues.

Q. How is your testimony organized?

A. This introduction concludes with a brief summary of our recommendations. In the next section, we summarize the electric ECOS methodology and the cost allocation process used in the JP. In the third section, we critique the methodology the Company used to classify and allocate various costs to customer classes. Following that section, we provide corrections to allocators that reflect our critique of the Company's cost allocation. Next, we address the subject of the proposed revenue distribution and recommend an alternative based on our modifications to cost allocation. The following section discusses Advanced Metering Infrastructure ("AMI") and how costs associated with it should be allocated. The final section addresses rate design.

Q. Would you please briefly summarize your recommendations?

A. Yes. We recommend a number of changes to the JP's allocation of electric distribution costs and rate design:

- The demand allocator for distribution plant should be based solely on non-coincident peak demand ("NCP");
- Primary distribution conductors should be classified purely as demand-related;
- The minimum system definitions used for secondary distribution plant should be modified to reflect true minimum loads;
- The AMI-related revenue requirement should be allocated based on energy in this rate plan;
- The Commission should instruct Con Edison to analyze cost causation and class beneficiaries regarding AMI and Reforming Energy Vision ("REV") for the next rate proceeding; and

- o Customer fixed costs should be reduced according to our recommended ECOS approach.

II. CON EDISON'S EMBEDDED COST OF SERVICE METHODOLOGY

Q. Please briefly summarize the JP's proposals regarding cost allocation.

A. The underlying foundation for the JP's proposed rate design and revenue distribution was the Company's ECOS study (JP at 55.) The Company's ECOS study was developed using a three-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 pre-filed Direct Testimony ("DAC Panel"), p. 30.) The second step was the classification of those functionalized costs. Third, the functionalized and classified costs were allocated to specific service classes and utility services using various allocation factors. These three steps serve to organize utility costs into categories to assist in allocating them. Allocation factors should reflect the factors that cause the Company to incur the various cost buckets.

Q. How does Con Edison summarize the results of its electric ECOS study?

A. Con Edison presents its electric ECOS results in prefiled Exhibit___ (DAC-2), Table 1A. Table 1A shows an overall system rate of return of 6.21%. It computes rates of return for individual customer classes, including the Residential and Religious service class ("SC1"), which under the Company's ECOS results has a rate of return of 5.12%. The rate of return indicates the relationship between revenues and costs; a rate of return lower than average suggests that the class is paying less in revenues than the costs that are allocated to it.

Q. Please provide a brief description of fully allocated electric ECOS, and explain what they measure.

A. ECOS studies are used to apportion utility rate base and operating expenses among the various customer classes on the basis of factors that should reflect cost causation. Test-year revenues, normalized for current rates and other factors, can then be compared to such allocated costs to calculate the rate of return earned from each class and the difference between costs and revenues (deficiencies or surpluses). Most costs are not directly attributable to any one customer class; therefore, they must be allocated according to a formula. The classification step is relevant because when costs are classified as a certain type, they are normally allocated on the basis of a characteristic which is related to that type; for instance, energy costs are allocated on the basis of energy. There are a number of generally accepted allocation methods, but there are some differences of opinion in the industry about allocation (and classification) as well.

III. ANALYSIS OF CON EDISON'S ALLOCATION APPROACH IN ITS ELECTRIC ECOS MODEL

Q. Have you found any fundamental problems with JP's approach to ECOS allocation?

A. Yes. We believe the purpose of the ECOS study is to reflect the decisions that underlie each of the costs the Company incurs. This is the fundamental cost causation principle that should govern an allocated ECOS study. For example, if the Company installs a particular type of equipment in order to meet its expected peak loads, the appropriate allocator for that plant item should be peak loads. As we will describe below, the JP's electric ECOS approach violates this principle in a number of specific allocation choices that would allocate too many costs on the basis of customer allocators, and, correspondingly, would underallocate costs associated with demand. This misallocation will generally result in overstating the costs associated with service to small customers and understating the costs associated with service to large customers.

Q. Would you summarize the allocation choices which you feel contribute to this overallocation on the basis of the number of customers?

A. Yes. These choices are as follows:

- o The JP's proposed demand allocator for secondary distribution plant reflects not only NCP demands, but also the sum of the individual customer maximum demands ("ICMD"), which is simply the sum of the demands that load data indicates individual customers put on the system at different times, and which is not appropriate for inclusion in the demand allocator.
- o The JP would inappropriately classify primary distribution conductors as partly customer-related, which would allocate them partially on the customer allocator.
- o The JP would classify secondary distribution plant as partly customer related, which we believe does not reflect cost causation.
- o The JP's implicit proposed allocation of AMI costs is inappropriate.

Q. The first issue you raise concerns with is the JP's main distribution system demand allocator. Please discuss this issue.

A. This issue relates to the delivery system portion of distribution costs. Fundamentally, the entire delivery system is designed to accommodate the peak demands (loads) on the various parts of the distribution system. Peak demands on different parts of the system differ.

This important point about the electric delivery system can be illustrated by an analogy to the road transportation system. The major highways should be planned to handle highest traffic periods of the whole region. The local roads must handle peak neighborhood traffic – in residential neighborhoods, probably "rush hour" traffic associated with work and school commutes; in industrial areas and commercial areas, the peak load times will be somewhat different. The local road peak loads are equivalent to electric class non-coincident peak loads. Likewise, in an urban setting, the entrance to parking for multifamily facilities should be able to handle the residential non-coincident peak loads. Roads are accordingly sized to meet actual anticipated peak load – they do not need to be large enough to accommodate every car in the neighborhood at once (i.e. the ICMD, which we discuss in more detail later in our testimony).

Returning to the electric distribution system, some parts of the distribution system are equivalent to the major highway system in that they are designed to serve load at the time of the system peak, whereas other parts (such as the local distribution-level poles, conductors, conduit and transformers) are designed to meet the peak local areas of the distribution system. The peak load of a residential area (or apartment building) will be driven by residential customer behavior, and the total system load will depend on the combined behavior of all classes. Again, the combined peak load of classes is labeled the NCP load.

It is generally accepted that most distribution costs are incurred in order to meet peak demands. It is also generally accepted that the relevant loads are the

NCP loads of the various customer classes. Later in this testimony we will discuss the JP's position that distribution costs are partly caused by the number of customers.

The JP applies a unique – and, in our opinion, inappropriate – alternative demand allocator to the demand portion of local distribution plant. The Company's prefiled direct testimony does not make clear that this allocator, designated D08, reflects factors beyond NCP demand. However, the ECOS Explanatory Notes in DAC Panel Exhibits and the Workpapers for Exhibit DAC-1 reveal that the allocator D08 is a weighted average of NCP and ICMD. For SC1 the NCP weight is 75%; for other classes, it is 50%. Neither the prefiled direct DAC Panel testimony nor the ECOS Explanatory Notes mentioned above explain the basis for the weights. We recognize that on pre-filed rebuttal testimony the DAC Panel provided some information regarding its suggested use of ICMD.

Q. What is ICMD?

A. ICMD is a hypothetical demand metric estimated by summing the peak demands of each individual customer in a given customer class. The ICMD imagines the total demand of a customer class if every individual customer in that class were to reach its maximum demand at the same moment. (In the transportation system analogy, ICMD would be the total of all vehicles driving on the road at once.)

Distribution systems do not actually experience ICMD. This is particularly the case for those customer classes with diverse individual customer loads (i.e., where different individual customers tend not to reach peak demand at the same time) such as residential customers. The Company suggests that its proposal to apply a 25% weight to ICMD for SC1, instead of 50% as for other classes, is in recognition of SC1's load diversity (its notes refer to an "adjustment… to allow for the diversity of individual customer loads in multiple dwellings.") (prefiled direct Exhibit (DAC-2) Schedule 2 p.10.)

Q. Does the evidence support this inclusion of the ICMD in the demand allocator?

A. No, it does not. To the contrary, the Company's responses to discovery requests concerning distribution planning criteria support allocation solely on the basis of NCP demands. For example, UIU Information Request No. 152 Exhibit___(UERP-JP-6) asked the Company to "Please describe with specificity why any portion of overhead lines, or underground lines, are sized to meet the sum of customer maximum demands [i.e., ICMD]." The Company responded:

> Similar to the Company's process for transformers, we do not "size" overhead and underground lines to meet the sum of customer demands. Each cable has a rated capacity, and the Company matches the cable capacity to the demand in a load area.

The Company thus admits and hence the JP reflects that the Company plans its delivery system to meet NCP demand, <u>not</u> ICMD. (Indeed, the Company's explanation makes no reference to the sum of customer demands.)

When asked directly to explain its rationale for including the ICMD in the D08 allocator, the Company replied:

> The closer the grid equipment is to the customer, the greater the importance of the individual customer maximum demands ("ICMD") and the further the grid equipment is from the customer, the greater the importance of class diversified peak demand (non-coincident peak or "NCP" in the ECOS study).
>
> (Exhibit___(UERP-JP-6) Company response to UIU Information Request 147.)

This response does not explain why the Company included ICMD in the D08 allocator. First, sections of secondary conductor or conduit or poles are not generally planned on the basis of individual customer demands. There may be large commercial or industrial facilities which require that their individual demands be taken into account with regard to plant that is close to their facilities, but this does not apply to residential customers. The fact that many residential customers live in multifamily buildings does not change the relevance of the class NCP load to utility planning. An apartment building's load is the sum of a number of residential customers, but the delivery system serving it is planned to meet its total load - i.e., it reflects the diversity of load in the building – which is illustrated by NCP.

The Company agrees that smaller customers should be treated differently than larger customers, since the Company proposes weighting ICMD 25% for residential customers and 50% for other customers. But the Company has provided no justification for using any ICMD to allocate secondary distribution costs to smaller customers.

Q. Did the Company use 100% NCP to allocate low-tension costs in previous cases (as we are advocated in this case)?

A. Yes. Prior to 1996, the Company used 100% NCP.

Q. Did the Company explain why it chose to include a NCP/ICMD allocator split starting in Case 96-E-0897?

A. Yes, evidence is found in the Company's 2009 Electric Rate Panel Rebuttal Testimony in Case 09-E-0428. On page 11 of that testimony, the Company admitted that it included a NCP/ICMD split as a "concession" for NYPA customers (as NYPA advocated for 100% ICMD at least since the 1996 case). This "concession" has been the Company's method for pushing more costs to residential customers for about 20 years.

Q. Did the Company justify why it is using a NCP/ICMD allocator split in this case?

A. The Company did not justify this choice in its direct testimony filed in this case. However, in Case 13-E-0300 the Company provided a Load Diversity Study and proposed that the study formed the basis for the NCP/ICMD split in that case.

Q. Does the 2013 Load Diversity Study justify the use of a NCP/ICMD allocator split in this case?

A. No. And as we noted in in our pre-filed direct testimony, sections of conductor, conduit, and poles are not generally planned on the basis of ICMD. As such, we do not recommend the use of this split in the ECOS study which ultimately is adopted in the JP.

Q. Next, please describe the Primary Customer Component and why you disagree with this proposed change in the JP's methodology.

A. The DAC Panel describes the development of Primary Customer Component as a change to its previous cost allocation methodology. The primary distribution system refers to the delivery infrastructure lying farther "upstream" from the end-use customer. Previously, the primary distribution system was fully classified as demand related. (Exhibit___(UERP-JP-6) Company Response to UIU Information Request 2-65.) The Company now proposes to classify part of its primary distribution system as customer-related, arguing that this approach "parallels" its approach to the secondary distribution system and also "recognizes increased emphasis on fixed cost recovery." (DAC Panel p. 18.) In response to Pace Energy and Climate Center ("Pace") Information Request Nos. 6-3 Exhibit___(UERP-JP-6), the Company adds that this "increased emphasis is simply part of an overall emphasis on better aligning delivery rates with the underlying costs of delivery service."

This reasoning is exactly backward. As we discuss later in our testimony, the Company's stated objective to "align delivery rates with the underlying costs of service" is entirely at odds with any proposal to classify primary distribution costs as customer-related, because primary distribution costs are not customer-related.

Q. How should primary distribution costs be classified and allocated, and why?

A. Primary distribution costs should be classified purely as demand related and should be allocated on the basis of the peak loads that they are designed to meet. Classifying any portion of primary distribution as customer-related is inappropriate because the number of customers has no bearing on how the primary distribution system is planned or constructed – the primary system is designed to meet the demands on it.

Primary systems exist because they are a more efficient way to carry significant loads than are secondary systems. They reduce line losses. The higher the demand on the system, the more primary systems become economic. If a utility were actually to build the least expensive system needed to provide a very minimal amount of electricity to customers (i.e., a "minimum system"), it could simply install secondary lines.

Another way of identifying the underlying cost causation is to consider the factors that necessitate incremental investment in the distribution system. A significant increase in demand on a portion of the system – even without any increase in the number of customers – would probably necessitate increasing the capacity (and therefore cost) of primary distribution lines and transformers. On the other hand, an increase in the numbers of customers with no increase in demand (which can occur where, for example, energy efficiency reduces per-customer demand), no new incremental investment would be required. In other words: demand, not customers, drives the cost of the primary distribution system.

Q. Your third bullet indicated a criticism of JP's calculation of the customer component of secondary distribution equipment. Please discuss this issue.

A. While we agree that meters and service plant are partly customer related, the secondary delivery system (poles, conductors, transformers) is primarily related to customer demand. Electric utilities plan and build their delivery system based primarily on the loads that they are expected to deliver. Contrary to the assumption used in the JP, the number of customers has little, if any, impact on the cost of the secondary distribution system (with the exception of plant such as meters and services).

We also note that in 2000, the most recent year for which we have found a reference, more than 30 states agreed with this approach and classified only meters and services as customer related. (Exhibit___(UERP-JP-10) Charging for Distribution Utility Services: Issues in Rate Design, p. 29.)[1]

Q. What is the rationale behind classifying a portion of the secondary delivery system as customer related in a minimum system concept?

A. The main rationale stems from electric utilities' obligation to serve even very small customers. A utility generally may not deny service to a new customer based on an expectation that the customer may consume little energy and thereby generate

[1] http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

little revenue. (However, a new customer can be required to contribute toward the utility's extra interconnection costs where the customer requires a larger than normal amount of distribution equipment.) On this basis, one may argue that some part of Con Edison's distribution investment is incurred simply to connect customers with minimal load, although it is clear that demand is the primary cost causative factor.

Q. Does this rationale support the JP's proposed minimum system methodology?

A. No. Even accepting, arguendo*,* the theoretical basis of the minimum system concept discussed above, the JP's approach is flawed because it applies a hypothetical "minimum system" that consists of much-larger-than-minimum-sized equipment. The Company's restatement of theory does not align with the approach it proposes to actually implement. For example, in its notes on the ECOS, the Company states "the customer component is the cost of the smallest secondary system theoretically needed to physically connect all of the existing service points if the system was not required to supply any load." (prefiled DAC Panel Exhibit __ (DAC-2) Schedule 2, p.5.) This sentence is a correct theoretical description of a minimum system definition of customer related distribution plant.

The JP's proposed approach would not implement this principle. The Company's minimum system analysis does not actually identify "the smallest secondary system theoretically needed to physically connect all of the existing service points." Instead, the Company's proposed "customer portion" is calculated based on an amount of plant that is significantly larger than the minimum amount needed to provide a connection. The JP thus based its analysis on a "minimum system" that is not a minimum system at all.

Q. Please discuss the specific aspects of the JP's minimum system calculations with which you find fault.

A. The specific calculation of the minimum system for Overhead ("OH") and Underground ("UG") conductor was agreed to in a Memorandum of Understanding ("MOU") signed by all parties in Case 04-E-0572. This MOU, dated July 24, 2005, further determined that this minimum size will be calculated using the weighted average unit cost of installed wire sizes from 1 to 10. (Exhibit___(UERP-JP-6) Information Responses to City of New York Nos. 203 and 204). See also Exhibit___(UERP-JP-9) "Memorandum of Understanding on Embedded Cost of Service Study".) We are not aware of any evidence relied upon at that time that demonstrated that this calculation actually reflects a minimum size, and no such evidence has been presented in this proceeding.

Q. Please discuss the JP's minimum system calculations for transformers.

A. The JP's proposed minimum system for OH transformers includes all transformers up to 25Kva, although in reality it has much smaller transformers in service. Its calculation for UG transformers not only goes up to 25Kva in size, but also includes equipment called autotransformers, which are transmission voltage (up to 480,000 Volts), and regenerators, neither of which are installed to serve minimum load.

Q. Is inclusion of any portion of transformers appropriate in a minimum system construct?

A. No. Transformers are installed to meet demand, and are not related to the number of customers. In a typical system, the electricity is stepped down from transmission voltage to primary voltage, using transformers located in a substation designed for this purpose. The electricity is then sent at primary voltage to another substation serving the neighborhood where the customer is located. It is again stepped down in that substation -- this time from primary voltage to secondary voltage. Next, it is sent through the neighborhood to the customer at secondary voltage.

The Company's responses to discovery requests confirm that its transformers are not related to the number of customers and thus should not form part of a theoretical "minimum system." For example, in its response to Exhibit___(UERP-JP-6) UIU 8-150, the Company states that it ". . . rates transformers and matches the transformer capacity to the demand in a load area." The Company's response to Exhibit___(UERP-JP-6) UIU 10-207 indicates that replacement transformer size is based on demand; specifically, the "sum of current demand, load factor of that demand and any known new additional load . . . ." Transformers are installed because most electricity is delivered via primary systems, which are themselves installed because of the need to provide significant capacity. Transformers are selected to meet current and expected demand levels.

Q. Do you have any additional comments regarding the JP's "minimum system" methodology?

A. Yes. The inconsistency between the Company's theoretical understanding of a minimum system that is used in the JP, and its empirical so-called "minimum system" proposal, demonstrates a fundamental shortcoming of the minimum system methodology. In practice, utilities do not install minimum systems, as it would make no sense to build a distribution system that provides a connection but little or no actual energy delivery. Instead, for most types of plant, the smallest-sized equipment that utilities actually install is significantly larger and more expensive than a theoretical minimum, as such equipment is designed to deliver service (i.e., to meet anticipated load) in addition to providing a mere connection.

Con Edison is no exception; most distribution plant on the Company's books is larger than minimum. For instance, with regard to Overhead Conductor, the minimum system is based on conductor sizes up to 10.0. However, in response to UIU Information Request 10-205 Exhibit___(UERP-JP-6), the Company states "The currently installed 4/0 Al is larger than the smallest size cable in use." The same response indicates that the Company "consolidated its sizes of cable used to minimize the number of conductors carried and associated stock, and for capacity concerns to minimize the number of times a section of cable is changed." In other words, it needs larger than minimum cable to meet demands, and it now stocks and installs only large cable to simplify its inventory.

Interestingly, the misallocation of costs resulting from the JP's proposed approach based on the Company's methodology may actually worsen over time. If peak demand increases over time, then new equipment the Company installs will correspondingly be larger and more expensive. The Company's approach would assign a portion of this larger capacity to its so-called "minimum system," and would in turn classify the associated higher costs as customer related. The prospect for escalating cost misallocation underscores the need to move away from the Company's flawed minimum system approach.

IV. UIU CORRECTIONS TO THE ECOS

Q. Have you attempted to correct some of the problems associated with the JP's cost allocation approach?

A. Yes. We have developed a revised version of the JP's electric cost results, presented in Exhibit___(UERP-JP-1), that corrects for each of the problems that were discussed above. We will discuss each of these corrections in turn.

Q. How did you correct the D08 allocator?

A. We simply utilized the NCP loads alone. This approach is simple, reflects sound engineering and planning principles, and is consistent with the methodology used by most utilities.

Some very large distribution customers may require that portions of the distribution system be planned to meet their individual demands. Thus some classes will have less diversity than the classes with smaller customers. As an alternative to utilizing only class NCPs in the D08 allocator, we could have attached some weight to the ICMD of classes that may have less diversity. We do not recommend this adjustment without further analysis of the potential ICMD weight and to which classes it should be applied, but we did calculate what the D08 allocator would have been if we had weighted some classes' ICMDs by 50%. The alternative D08 allocation percentages are shown in the table below:

Table 1: Corrected D08 Allocator Components

Service Class	Description	ICMD	NCP*	Con Edison D08	Revised** D08
SC01	Res & Religious	49.832%	35.729%	39.265%	33.883%
SC02	General Small	6.221%	4.768%	6.187%	4.522%
SC05 CONV	Electric Traction	0.001%	0.001%	0.001%	0.002%
SC05 TODL	Electric Traction	0.017%	0.021%	0.020%	0.023%
SC06	Street Light & Signal	0.010%	0.016%	0.013%	0.015%
SC08 CONV	Apt. House	2.513%	4.296%	3.495%	3.946%
SC08 TODL	Apt. House	0.166%	0.273%	0.226%	0.255%
SC09 CONV	General Large	25.275%	31.596%	30.269%	34.180%
SC09 TODL	General Large	8.280%	12.438%	10.792%	12.186%
SC12 CONV	Apt. House Heating	0.236%	0.344%	0.303%	0.342%
SC12 TODL	Apt. House Heating	0.304%	0.450%	0.393%	0.444%
SC13 TODL	Bulk Power	0.000%	0.000%	0.000%	0.000%
	CON ED SUBTOTAL	**92.855%**	**89.931%**	**90.966%**	**89.799%**
	NYPA SUBTOTAL	**7.145%**	**10.069%**	**9.034%**	**10.201%**
	TOTAL SYSTEM	**100%**	**100%**	**100%**	**100%**

*UIU Recommended Allocator

**Weights 50% NCP and 50% ICMD except for SC1 and SC2, which are 100% NCP

This analysis indicates that if it were appropriate to include ICMD in D08 allocator, it would likely result in lower costs allocated to SC1 and SC2.

Q. Have you attempted to correct the JP's allocations of secondary plant based on a minimum distribution system?

A. Yes. We made the following modifications:

First, with regard to the plant included in OH conductor, we can see on Exhibit___(UERP-JP-1), OH Con Min Sys, that the conductor sizes used in Con Edison's minimum calculation range from 0 to 1.0 to 10.0. According to the response to UIU Information Request No. 205 Exhibit___(UERP-JP-6), a conductor size of 0 means there is no size for those plant items specified on the Company's books. (We assume that this lack of information is the reason that this plant was not included in the computation specified in the MOU, and if so, we agree with this exclusion.) The minimum size in use is 1.0, which we used as the minimum size for our calculations. This resulted in a total customer portion of $6,425,825, or 4.84% of OH Conductor being treated as customer related, rather than the $19,839,766 (or 14.94%) that Con Edison utilized.

For UG conductor, we also used only conductor up to size 1.0. The resulting customer related percentage is 3.5%, much less than the 21.13% Con Edison recommends.

Second, we treated both OH and UG transformers as entirely demand related, and allocated them on our revised D08 allocator. From this corrected minimum system calculation we have derived an updated classification and allocation of delivery system costs.

Q. Have you developed any estimates of the impact of your recommendations regarding the allocation of distribution plant?

A. Yes, we have. We developed estimates of the impact of applying our recommended allocation approach, which are summarized in the table below for residential and small commercial customers. The "UIU Recommended" case includes all the changes described in this testimony. Exhibit___(UERP-JP-2), Exhibit___(UERP-JP-3), Exhibit___(UERP-JP-4) and Exhibit___(UERP-JP-5) are models that provide the calculations supporting these results.

Table 2: Rate of Return Results under Corrected ECOS Model

	SC 1 Residential		SC 2 Small Commercial	
	Rate of Return	Deficiency/Surplus*	Rate of Return	Deficiency/Surplus*
ConEd Proposal	5.12%	($37,333,708)	5.27%	($3,995,747)
Primary Lines 100% Demand	5.38%	($11,310,577)	5.78%	$0
D08 is NCP Only for All Classes	5.53%	$0	6.21%	$0
All Changes to Secondary Minimum System**	5.69%	$0	6.97%	$4,221,597
UIU Recommended	**6.58%**	**$0**	**9.28%**	**$37,560,747**

* Deficiencies are negative** Secondary Minimum System Changes:

- OH Conductor: Min. size of 1; 4.8% Customer-Related
- UG Conductor: Min. size of 1; 3.5% Customer-Related
- OH Transformers: 0% Customer-Related
- UG Transformers: 0% Customer-Related

This model shows that neither SC1 nor SC2 actually have deficiencies, and SC2 has a surplus. This is not surprising, as each of the errors in the Company's ECOS we identified tend to overallocate costs to small customers.

V. REVENUE DISTRIBUTION

Q. What factors do you think should be considered in determining how the approved rate increase should be distributed across the various classes?

A. We propose utilizing the results of our recommended ECOS study. If the Commission found that changing rates by the full deficiency was high enough to be a problem for some particular classes, it could mitigate those increases by further increasing the revenue requirements resulting from our ECOS study from classes which were below the minimum tolerance band.

Q. How is the revenue increase distributed among various electric customer classes in the JP?

A. The revenue distribution set forth in the Joint Proposal is based on the Company's ECOS results, which are summarized in Table 1A from Appendix 19 Table 1A to the JP ("Table 1A"). The "Initial Surplus/Deficiency" shown is the amount of dollars needed to bring each class's rate of return within the 10% tolerance band surrounding the system rate of return. Under the JP's revenue requirement, this tolerance band is between 5.49% and 6.71%. The sum of the initial surpluses and deficiencies is a net surplus of about $36 million. The rate classes with initial surpluses have their surpluses adjusted by a total of this amount. The "Adjusted Surplus/Deficiency" of each rate class then sums to zero.

Due to the its proposed change to allocate more costs on a customer basis, the realigned revenues are based on one third of the adjusted surplus or deficiency amount in the first rate year and collect the remaining two thirds over subsequent rate years. (JP at 55) Thus, the total "Re-aligned" revenues are equal to the revenue at current rates plus one third the adjusted surplus or deficiency from Table 1A, noted above. This is calculated separately for each rate class. The JP's requested rate increase of approximately $213 million is then allocated to each class on the basis of these "Re-aligned" revenues. (Appendix 19 Table 2 Page 1 of 3, see also Electric Rate Panel, pp. 10:18-11:5; and Rate Design Workpaper "Revenue Allocation.Multiple Years.xls".)

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

A. Yes. The tolerance bands refer to a ±10% tolerance band around the total system rate of return shown in the ECOS. In other words, a class whose ECOS rate of return fell within this tolerance band (i.e., 5.49% to 6.71%) was not considered to have a "surplus" or "deficiency." Classes that fall outside this range 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. Have you calculated what class increases would result from your recommended cost allocation and the revenue set forth in the JP?

A. Yes. The results shown in Table 2 above indicate that the SC1 class is well within the tolerance bands, while the SC2 class is above the upper tolerance band. Should AMI costs be allocated on the basis of energy, as we recommend in the following section, there will be a further shift of costs from small energy users to large energy users.

VI. REVENUE REQUIREMENTS AND ALLOCATION

Q. Is your recommended revenue allocation and rate design based on the revenue requirement set forth in the JP?

A. Yes. Using the revenue requirement set forth in the JP has informed our revenue allocation and rate design recommendations presented herein.

Q. What does the JP include for an electric revenue requirement increase?

A. The JP includes an electric revenue requirement increase of $194 million during for each Rate Year, excluding Gross Receipts Tax. This results in a 4.3% increase in delivery revenues. (See JP Workpapers “Revenue Allocation.Multiple Years.xls,” “Revenue Allocation.Multiple Years = Yr 2.xls,” “Revenue Allocation.Multiple Years = Yr3.xls”.)

Q. Have you reflected the JP electric revenue requirement in the revenue allocation and rate design calculations presented in this testimony?

A. Yes.

Q. Please describe the steps involved that you used to take the electric ECOS model output and create the proposed surplus and deficiency used during the revenue allocation process.

A. We used Con Edison’s electric ECOS model and made changes to the inputs and allocators in that model to reflect the recommendations we made in our pre-filed Direct Testimony. We then followed the same methodology used by Staff and Con Edison to develop the proposed surplus and deficiency for each class.

Exhibit ___ (UERP-JP-7) Schedule 1 shows the steps used to take the electric ECOS model output and create the proposed surplus and deficiency used during the revenue allocation process. First, the rate of return for each class (Schedule 1 column A) is compared to the system rate of return of 6.10%, based on 2013 costs and estimated revenues based on historical 2013 sales at current rates. For those classes that have rates of return outside the range of the 10% tolerance band surrounding the system rate of return (5.49% to 6.71%), the model calculates the amount of dollars needed to bring each class to the upper or lower bound of the tolerance band (with the exception of SC13). This is termed the "initial surplus or deficiency" and shown in Column B in Schedule 1.

The sum of these initial surpluses and deficiencies for all classes is a net deficiency of about $50 million. This deficiency is then allocated to the rate classes on the basis of sales revenues, as shown in column C of Schedule 1. Note that a straight allocation on revenues would result in changing SC 5 from a net deficiency to a net surplus. Therefore, column C includes a small additional adjustment such that this rate class has a zero deficiency. The dollars are only allocated to classes with an initial deficiency. In other words, classes that have surpluses (i.e., those classes that are overpaying), do not receive decreases; this treatment reduces the increases that are allocated to the deficient classes.

The resulting adjusted surplus and deficiency in Schedule 1, column D is multiplied by one third to create the surpluses and deficiencies in column E, which are used in the calculation of re-aligned revenues for each Rate Year.

Q. Con Edison's calculation of class revenue requirements reflected both a tolerance band and a mitigation of class revenue changes by reducing the resulting surpluses and deficiencies by two-thirds – which is the same method set forth in the JP. Have you utilized the model that reflects this same approach in the above calculations?

A. Yes.

Q. You have utilized the Company's proposed +-10% tolerance bands as set forth in the JP. What is your position regarding the tolerance bands?

A. We have accepted these tolerance bands as a means of moderating rate changes. In addition, tolerance bands are a way of recognizing that cost allocation results are never perfect and may change significantly from one rate case to the next.

Q. What is your position regarding the spread of class revenue changes (increases) over three years as set forth in the JP?

A. Spreading a revenue increase over multiple years is a technique that mitigates rate impacts. The amount of mitigation that is appropriate is related to the size of the overall increase that is awarded and to the amount of divergence between class rates of return. We believe that in this case, it may be appropriate to spread out revenue increases over three years.

Q. How do you propose to allocate the revenue requirement set forth in the JP to the electric service classes?

A. In our pre-filed Direct Testimony we proposed allocating the portion of the electric revenue requirement impact not related to AMI on the basis of realigned revenues from UIU's recommended ECOS methodology. We continue to recommend and utilize this allocation. We also recommended that AMI costs should be allocated on the basis of energy in this proceeding. To reflect this in our calculations, we used an estimate of the 2017 electric revenue requirement impact of AMI that Con Edison provided in response to discovery in another case (Response to DPS-7 in Cases 15-E-0050 and 13-E-0030, Attachment 1) Exhibit___(UERP-JP-6) DPS-7 Con Edison AMI IR Answer. The AMI electric revenue requirement for Rate Year 1 is approximately $29 million. We are not advocating Con Edison's projection of AMI costs, but are utilizing this projection as a proxy for AMI costs that have been included in this revenue request set forth in the JP. We allocated this amount to the classes based on the projected rate year total kilowatt-hour ("kWh") for each class used in the JP. The issue of AMI allocation will be discussed further in Section IV of this testimony, including a rebuttal to Staff's recommended allocation of AMI costs.

The remaining portions of the $194 million were allocated to the classes using the same methodology set forth in the JP, although we relied on UIU realigned revenues.

Q. What are realigned revenues?

A. Realigned revenues refer to the sum of projected delivery revenues at current rates and sales level shown in the JP and the proposed surplus or deficiency from UIU's electric ECOS model. This amount is calculated for each rate class. Schedule 2 of Exhibit ___ (UERP-JP-7) shows the UIU recommended realigned revenues.

Q. In your pre-filed Direct Testimony you recommended using total kWhs and not realigned revenues to allocate AMI costs to the classes. How does using kWhs impact each rate class?

A. Allocator percentages based on realigned revenues and kWhs are also shown in Schedule 2 of Exhibit__ (UERP-JP-7). The difference between the realigned revenue percentages and the energy percentages indicate how using kWhs will affect each class. The kWhs that form the basis for the percentages in the table reflect the forecast used in the JP. As the table shows, the energy allocator allocates significantly less AMI costs to residential and small commercial classes compared to an allocation on realigned revenues.

Q. How are final delivery revenues calculated?

A. After the revenue requirement increase of $194 million is allocated, the resulting allocated increase is added to the proposed surplus or deficiency from UIU's ECOS results to estimate the total increase or decrease in delivery revenue for each class. Exhibit ___ (UERP-JP-7) Schedule 3 shows the final class delivery revenues using UIU electric ECOS results and AMI allocation.

Q. Please describe in more detail how you allocate the revenue requirement increase of $194 million to customers using your recommended electric ECOS results.

A. The allocation is done in seven parts. Each part is listed below, and the letters correspond to the columns in Exhibit ___ (UERP-JP-7) Schedule 4:

A. Electric AMI costs are allocated on rate year total kWh;
B. Transmission Congestion Contract ("TCC") revenue imputation is allocated on realigned revenues, except for NYPA;
C. Rate year monthly adjustment clause ("MAC") increase is allocated on rate year total kWh, except for NYPA;
D. Rate year purchased power working capital ("PPWC") change is allocated on rate year full service kWh, except for NYPA;
E. Low income program impact is assigned to the residential class;
F. New Program Costs are allocated on realigned revenues (except for NYPA for which $138,818 is assigned); and
G. Remaining dollars are allocated on realigned revenues.

The total revenue requirement increase for each class is the sum of the allocated dollars in A-G listed above. Schedule 4 shows the result of the UIU proposal in column H. This column H is the same as column B shown in Schedule 3 of the same exhibit.

Q. Have you reviewed the May 19, 2016 Commission Order in Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* ("REV Ratemaking Order"), ("REV Ratemaking Order") and do you find it to be relevant to cost allocation and rate design in this proceeding?

A. Yes. This Order is aimed in part at establishing ratemaking changes that reflect the current and future utility environment, and that will "enable the growth of a retail market and a modernized power system." (REV Ratemaking Order p. 5.) The Order states clearly that "Fixed charges should recover only costs that are invariable with usage." (*Id.* p.119.)

Q. How does the REV Ratemaking Order relate to the classification of distribution plant in this electric proceeding?

A. Customer charges (i.e. fixed charges) are normally justified by relating them to costs that cost of service studies treat as customer related. Therefore, the Commission's position on rate design as expressed in the REV Ratemaking Order appears to support UIU's position that much of the distribution plant that Con Edison classifies as customer-related should be considered demand-related, because it varies with usage. The Company, Staff, and the City recommended, in prefiled testimony and ultimately applied in the JP, splitting distribution delivery plant into customer-related and demand-related components based on the assumption that some portion of these costs were caused by the number of customers on the system. It does not follow that even if some portion of costs is identified as a minimum system that these costs will vary with the numbers of customers. Investment in poles, conductors, conduit, and transformers is basically invariant with regard to the number of customers, but is variant with regard to the demand of those customers.

Q. Are there other positions taken in the REV Ratemaking Order that are relevant to cost allocation and rate design?

A. Yes. The Order states: "The correct characterization of different types of system costs has long been a fixture of rate design debates. We will continue to observe the principle of cost causation as REV progresses, but the characterization of costs will evolve." (*Id.* p.122.) The characterization (classification) of distribution costs has been the subject of debate is this electric proceeding. The REV Order encourages rates that will impact customer behavior (i.e. energy and demand charges, not customer charges), which militates against classifying costs as customer-related, and which is relevant to the discussion below of other parties' comments in this proceeding.

VII. ADVANCED METERING INFRASTRUCTURE

Q. Please provide an overview of the Company's AMI program.

A. Through this program, the Company will replace or upgrade all existing meters across its service territory with approximately 3.6 million advanced electric meters and 1.2 million advanced gas meters across its service territory. (pre-filed direct AMI Panel, p. 6.) In addition to the AMI meters, the Company will install a meter communication network and IT platform to manage two-way communication with the meters. (Id., p. 14.) In its Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions, issued March 17, 2016 in Cases 15-E-0050 et al, the Commission conditionally approved the Company's implementation of AMI as described in its AMI Business Plan, included in the Company's testimony in this case as Exhibit ___ (AMI–001). This Order does not, however, prescribe any particular mechanism for recovering costs associated with AMI, nor does it determine how those costs are to be allocated among customer classes.

Q. What are the purported benefits of the AMI program?

A. The Company describes several customer and system benefits:

> Con Edison believes that AMI will enhance the customer experience, unlocking greater participation in demand management programs, improving outage restoration and operational performance, and facilitating the integration of DER that will substantially increase the ability of customers to engage in the management of their energy usage.
>
> (AMI Panel, pp. 27-28.)

The advanced metering functionality allows greater access to near real-time demand and pricing information, which allows for more control and management by both customers and system operators. Customers will theoretically also be able to more easily participate in distributed energy resource ("DER") and demand response ("DR") programs. On the system level, the Company claims that AMI meters provide several benefits, including improved metering processes to eliminate the need for manual meter-reading, and improve outage management by allowing more reliable information and reduced cost impact of false outages. (Id., p. 27.) The Company states that the AMI program will also yield environmental benefits derived from reduced GHG emissions due to Conservation Voltage Optimization, reduced vehicle emissions from meter-reading and outage response, and reduced energy usage (and GHG emissions) from increased customer participation in DR programs. (Id., pp. 32-33.)

Q. Has the Company performed a Benefit Cost Analysis ("BCA") of the AMI program?

A. Yes, it has. Prefiled Exhibit ___ (AMI–001), Con Edison's AMI Business Plan, includes the latest BCA. The Company quantified total projected program costs of $1.6 billion and total benefits of $2.7 billion (20 year net present value ("NPV")), for an estimated net benefit of $1.1 billion and a discounted payback period of 10 years. (Id., pp. 40-41.)

Q. What costs associated with this program are included in this rate case?

A. For capital costs, the Company proposes to spend $173.2 million in Rate Year 1, $194.9 million in Rate Year 2, and $285 million in Rate Year 3. The Company proposes to allocate 83% of the costs of the AMI program to electric customers and 17% of the costs of the program to gas, reflecting the Company's current allocation of common plant. (Id., p. 18; see also prefiled Exhibit ___ (AMI–002).)

The Company also expects to incur Operations and Maintenance ("O&M") costs associated with developing the IT infrastructure and staffing the AMI Operations Center. These costs are expected to be $6.2 million in Rate Year 1, $14.6 million in Rate Year 2, and $24.4 million in Rate Year 3. (prefiled AMI Panel, pp. 21-22; see also prefiled Exhibit ___ (AMI–003).)

The Company anticipates customer O&M savings related to billing, call center activity, field meter services, and meter reading. These savings are expected to begin in Rate Year 2 with $1.2 million, and $9.3 million in Rate Year 3. (prefiled AMI Panel, pp. 24-25; see also prefiled Exhibit ___ (AMI–004).)

Lastly, the Company anticipates electric operations O&M savings related to improved outage identification, reduced false outage response, and more efficient service restoration. These savings are expected to begin in Rate Year 2 with $0.4 million, and $1.3 million in Rate Year 3. (pre-filed AMI Panel, pp. 26-27; see also pre-filed Exhibit ___ (AMI–005).)

Q. Earlier, you mentioned the allocation of AMI costs as a shortcoming of the Company's with the ECOS. How have AMI costs been reflected in this ECOS study which has been used in the JP?

A. The Company's ECOS model is based on a 2013 test year. It does not include any AMI costs.

Q. To which FERC accounts are AMI costs currently assigned?

A. All AMI costs booked to date have been included in FERC 1070, Construction Work in Progress. (Exhibit___(UERP-JP-6) Company Response to UIU Information Request 99.)

Q. To which FERC accounts will AMI costs be assigned once they are incorporated into an ECOS model? How are these accounts allocated?

A. The Company has refused to identify the ultimate breakdown of AMI plant among FERC accounts. It appears that the Company does not currently know how its AMI costs will be booked. (Exhibit___(UERP-JP-6)Company Response to UIU Information Request 93.) However, because the Company has not proposed any special accounting treatment for these costs, we assume they will eventually be booked and allocated in the same manner as other costs. For example, we assume that AMI meters will be reflected in the meter account and will be allocated on the number of meters weighted by the costs of the meters. (Exhibit___(UERP-JP-6)Company Response to UIU Information Request 98.)

Q. Is there any evidence that Con Edison has considered relating customer benefits of AMI with the allocation of AMI costs?

A. No. In fact, the opposite appears to be true. In discovery, UIU asked whether the Company thought "it is appropriate to allocate AMI costs on the basis of benefits received by different customer classes?" The Company's response noted that costs are not allocated on the basis of benefits, and did not indicate whether it might be appropriate to do so. (Exhibit___(UERP-JP-6))_ Company Response to UIU Information Request 194.) A further question, Exhibit___(UERP-JP-6) UIU Information Request 197, asked the Company to compare the benefits that might be received with its set of "trackers;" the Company's response referenced the general benefits of the trackers, but not how or to what extent those benefits accrue to customers. UIU submitted additional questions regarding the benefits AMI may provide customers in Case 15-E-0050. (Exhibit ___(UERP-JP-6) Company Response to UIU Information Request 2-9.) In questions 3-4 UIU asked the Company to describe how the benefits listed in the AMI business plan will accrue to customers. The Company provided just general information stating the benefit will result in a decrease in delivery rates, supply charges, or both.

Q. Is the panel familiar with a report that discusses the unique cost recovery issues presented by AMI?

A. Yes, the Regulatory Assistance Project released a report in July 2015 titled "Smart Rate Design for a Smart Future" which discusses the cost recovery issues that may arise with the installation of smart meters or AMI. (Exhibit ___(UERP-JP-8).)

Q. Why are you addressing the allocation of AMI costs, given that the amounts reflected in this proceeding are small?

A. The AMI costs as applied to this JP are apparently allocated across all classes on the basis of other costs. In the future the costs will grow significantly. If they continue to be allocated similarly to other costs in the same FERC accounts, such allocation ignores the actual cost causation (or benefit) of AMI costs. This issue needs to be carefully considered in this and future proceedings. In addition, the JP does not provide the expected revenue requirement impact from AMI.

Q. Why would the Company's apparent proposed treatment as set forth in the JP not be appropriate?

A. The Company's proposed allocation fails to consider the purpose of the AMI program and the basis of its associated costs. The Company's entire justification for installing AMI is not that the system is necessary (it isn't) but rather that it would yield net benefits. For example, consider AMI meters. AMI meters will replace existing meters and will provide the same basic metering functions, but will cost significantly more than basic existing meters, which the Company has justified on the basis that the AMI meters (working in conjunction with the rest of the AMI system) will yield cost savings and other benefits (referred to jointly as "benefits") that exceed their costs. (prefiled Company AMI Panel, p.40; Exhibit ___ (AMI–001), Con Edison AMI Business Plan, p. 56.)

The Commission would likely not have approved the Company's AMI business plan if AMI's projected costs had exceeded its expected benefits. (<u>See</u> Case 14-M-0101, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016).) AMI's projected benefits are therefore the reason that the system is being installed – in other words, AMI's expected benefits drive its cost causation.

Q. What does this mean in terms of appropriate AMI cost allocation?

A. Cost allocation should follow cost causation. In the case of AMI, whose costs are justified and caused entirely on the basis of the benefits they are expected to yield, costs should be allocated to customers on the basis of the portion of benefits that customers will receive. These benefits will not automatically accrue to all customers in the same proportions as the costs of serving those customers; nor are they likely to flow according to the number of meters in each class.

We note that this "value of service" principle, in addition to reflecting cost causation, is consistent with and would advance the Commission's objectives in the REV proceeding. For example, in the REV Track Two Order, the Commission observed that "[w]hile cost-of-service ratemaking has served reasonably well for the last century, it was developed under several assumptions that may no longer hold" (p. 3), and found that instead, "[utility] earnings must be connected to increased customer value" (p. 5).

Q. What is the appropriate allocation of AMI costs in the JP?

A. We recommend that the Commission employ this "value of service" approach to the allocation of AMI costs, which would allocate AMI costs according to its benefits.

Q. How can this "value of service" principle be implemented in this rate proceeding?

A. It can be closely approximated in this proceeding. To date, the Company has failed to determine the allocation of projected AMI benefits among customer classes to date. But this does not justify a cost allocation that ignores cost causation. Until benefit-allocation data are available, we recommend that the Commission use energy as a proxy determinant of AMI benefit and cost allocation.

We recommend energy because the amount of benefits a customer receives from AMI will likely be highly correlated to the customer's size and level of sophistication. AMI will provide customers with a rich set of usage data that will be much more useful to those larger customers that have more opportunity to understand and modify their consumption accordingly. Furthermore, larger customers will benefit more as reduced outages yield lower energy costs. We therefore recommend that AMI costs be allocated on the basis of energy unless and until the Company provides analyses that justify an alternative approach.

VIII. RATE DESIGN

Q. How are customer charges for service classes SC1, SC2, and SC6 reflected in the JP?

A. With the exception of a reduction for some SC2 customers, customer charges remain the same. This mostly reflects the Company's initial proposal not to increase customer charges. We note that the JP proposes to reduce the existing monthly customer charge for SC 2 customers with unmetered service by $4.41 to reflect the removal of SC2's allocation portion of metering costs in the 2013 ECOS study. JP further notes that usage charges for all SC2 customers will be increased to offset the resulting revenue shortfall. (See JP at 56.)

Q. According to the JP, what are the delivery volumetric rates for Rate I customers in residential rate class SC1 for Rate Year 1?

A. The JP continues to apply the Company's rate structure to keep the current inclining block rate structure for summer and flat rates for winter. The winter flat rate is equal to the first block of the summer rate. The volumetric delivery rates increase approximately 8.16% in order to recover the target revenues set forth in the JP.

Q. Similarly, what are the general small commercial SC2 Rate I volumetric delivery charges set forth in the JP?

A. The SC2 volumetric delivery charges increase by approximately 9.23% (summer) and 9.21% (winter).

Q. Please summarize the current and proposed rates for Rate I customers in rate classes SC1 and SC2.

A. The table below summarizes the rates.

Table 3: JP Proposed Rate Changes to SC1 and SC2 in Rate Year 1

		SC 1		SC 2	
		Current (1/1/2016)	Proposed	Current (1/1/2016)	Proposed
	Customer Charge	$15.76	$15.76	$26.01	$26.01
Summer Volumetric Delivery Rates	SC 1: 0-250 kWh SC 2: 0-2000 kWh	$0.08901	$0.09627	$0.1073	$0.1172
	SC 1: >250 kWh SC 2: >2000 kWh	$0.10232	$0.11067	$0.1073	$0.1172
Winter Volumetric Delivery Rates	SC 1: 0-250 kWh SC 2: 0-2000 kWh	$0.08901	$0.09627	$0.0901	$0.0984
	SC 1: >250 kWh SC 2: >2000 kWh	$0.08901	$0.09672	$0.0901	$0.0984

Q. Do you agree with the rate design methodology for SC1 and SC2 electric customers applied in the JP?

A. Yes; however, the delivery volumetric rates for SC1 and SC2 would be lower if the Commission adopts our recommendations with respect to the ECOS model.

Q. Please provide your comments on the customer charge set forth in the JP.

A. First, we believe that customer charges set at computed customer costs do not necessarily provide appropriate price signals. It is much more important that volumetric charges be set at appropriate levels. Volumetric charges will influence customer behavior; it is unlikely that higher or lower customer charges will affect customer behavior.

The Company provides estimates of unit customer costs for each rate class as part of its ECOS model – the Company's ECOS model which has been ultimately used in the JP. However, its estimates incorporate significant allocation of high tension and low tension system plant on a customer basis. As described earlier in this testimony, we recommend a much lower allocation on a customer basis for these costs. The table below shows a comparison of these unit costs and current customer charges for SC1 and SC2. The unit costs from the "UIU Recommended" ECOS model are below the current monthly customer charges.

Table 4: SC1 and SC2 Customer Charges Under Company Proposed and UIU Recommended Models

	SC 1 Monthly Customer Cost ($/customer)	SC 2 Monthly Customer Cost ($/customer)
Per JP Electric ECOS	$22.14	$38.11
Per UIU Recommended ECOS	$14.00	$21.96
Current Customer Charge	$15.76	$26.01

Our estimated customer costs are lower than the Company's estimate, but more important, are lower than the current as well as JP customer charges for SC1 and

SC2. We recommend reducing the current customer charges for SC1 and SC2 accordingly.

The reduced customer charges will also result in higher volumetric energy charges. We believe it is much more important to consider the price signals provided by energy charges, and higher energy charges will be an incentive for customers to limit energy use. This is also consistent with the Commission's objectives in REV to give customers more control over their energy bills.

Q. In your pre-filed Direct Testimony, you recommended that electric customer charges for SC1 (residential heating and non-heating) and SC2 (general small commercial) should be reduced. Do any of the testimonies and orders to which you have responded affect that recommendation?

A. Yes. Other testimonies presented in these cases and the REV Ratemaking Order provide strong support to that recommendation. For instance, p. 119 of the REV Ratemaking Order states that "Rate design should encourage economic DER and conservation." The revenue requirement recommended by Staff will result in a very small average increase to electric rates. One result of this is that if the existing customer charges are maintained, the increase to energy charges will also be very small. This is inconsistent with the emphasis in the REV Ratemaking Order on rates that will encourage efficient consumption.

The REV Ratemaking Order also noted that "...Staff analyzed rate design in the context of REV and found that, much like the utility revenue model, current rate design practices fail to provide adequate incentives and price signals that are suitable for a modern electric system." (p.109.) We note that there is no evidence that existing customer charges contribute to adequate incentives and price signals.

While this Order may be primarily setting the groundwork for future ratemaking changes, it is reasonable to reflect these goals in the current Con Edison electric case to the extent possible.

Q. Did the revenue requirement set forth in the JP result in you changing your recommendation regarding the customer charge?

A. No, it did not. The revenue requirement and the allocation of AMI do not change the numbers presented in Table 4.

Q. Do you have any other comments on rate design set forth in the JP?

A. Yes. Since the JP does not consider whether the existing seasonal differential and volumetric block rate difference reflect costs differences and provide appropriate price signals to customers, we recommend that the Commission require the Company to provide this analysis in the next rate proceeding.

Q. Please provide your comments on marginal costs.

A. As a marginal cost study has not been used to inform decisions on residential rate design in this proceeding and is not reflected in the JP. We recommend the Company perform an analysis of using marginal cost to develop its tail block summer rate for SC1 customers as part of its next rate case proposal.

Q. Does this conclude your direct testimony on the JP?

A. Yes, it does.