conEdison
a conEdison, inc. company

Marc Richter
Associate General Counsel

November 30, 2007

By Overnight Mail

Hon. Jaclyn A. Brilling, Secretary
New York State
Public Service Commission
Three Empire State Plaza
Albany, NY 12223

Re: Case No. 07-E-0523
Con Edison Electric Rate Case

Dear Secretary Brilling:

Attached is an original and 25 copies of the Company's Initial Brief in the referenced proceeding. All parties have been served via e-mail.

If you have any questions, please contact me.

Very truly yours,

Attach.
cc Hon. William Bouteiller, Administrative Law Judge
Hon. Michelle L. Phillips, Administrative Law Judge
Hon. Rudy Stegemoeller, Administrative Law Judge
All Active Parties (via electronic mail)

Consolidated Edison Company of New York, Inc.
4 Irving Place New York NY 10003 212 460 4615 212 677 5850 fax richterm@coned.com

BEFORE THE NEW YORK STATE
PUBLIC SERVICE COMMISSION

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In the Matter of	:	
	:	
Proceeding on Motion of the	:	
Commission as to the Rates, Charges,	:	**Before**
Rules and Regulations of Consolidated	:	**Hon. William Bouteiller**
Edison Company of New York, Inc. for	:	**Hon. Michelle L. Phillips**
Electric Service.	:	**Hon. Rudy Stegemoeller**
	:	**Administrative Law Judges**
	:	
P.S.C. Case No. 07-E-0523	:	
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INITIAL BRIEF ON BEHALF OF
CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
IN SUPPORT OF A PERMANENT ELECTRIC RATE INCREASE

Dated: November 30, 2007
New York, New York

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BEFORE THE NEW YORK STATE
PUBLIC SERVICE COMMISSION

In the Matter of	:	
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.	:	**Before** **Hon. William Bouteiller** **Hon. Michelle L. Phillips** **Hon. Rudy Stegemoeller** **Administrative Law Judges**
P.S.C. Case No. 07-E-0523	:	

INITIAL BRIEF ON BEHALF OF CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. IN SUPPORT OF A PERMANENT ELECTRIC RATE INCREASE

I. OVERVIEW OF PROCEEDING

A. Procedural Overview

1. Initial Filing

On May 4, 2007, Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") filed with the Public Service Commission (the "Commission") a proposal to increase the charges for electricity service and make other changes to its Schedule for Electricity Service, P.S.C. No. 9 - Electricity, and its Schedule for Retail Access, P.S.C. No. 2 - Retail Access. Con Edison also proposed to increase the charges for electric service and make other changes to its Schedule for New York Power Authority ("PASNY") Delivery Service - PASNY No. 4 and to its Schedule for Economic Development Delivery Service ("EDDS") as applicable to EDDS No. 2 delivery to economic development customers. Under the Company's initial filing, these changes were to become effective June 3, 2007. The rates contained in these

amendments were designed to produce a revenue increase of $1.225 billion or an average increase of approximately 11.6 percent, including projected supply costs and gross receipts taxes, based on the estimated level of sales for the Rate Year, *i.e.*, the twelve months ending March 31, 2009.

The Company also presented a three-year rate proposal as an alternative to a one-year rate plan. Under the Company's proposal, the rates for the first rate year would be the base from which projections are made for the second and third years of the three-year plan. These projections result in the Company seeking increases in the second and third rate years of $323.1 million and $381.0 million, respectively.

2. <u>Leaves Suspended</u>

By orders dated May 23, 2007, and September 21, 2007, the Commission suspended the proposed electric rates first through September 30, 2007, and subsequently through March 30, 2008.

3. <u>Conferences</u>

On or about June 6, 2007, the Company held a Technical Conference for all interested parties. Five Company presenters provided overviews of areas addressed in the filing, including infrastructure investments, customer service, energy efficiency, financial issues and rate design, and answered questions from the parties.

By notice dated May 30, 2007, a Procedural Conference was held on June 18, 2007, before Administrative Law Judges William Bouteiller, Elizabeth H. Liebschutz, and Michelle L. Phillips to discuss procedures for the case and a case schedule. Additionally, Company representatives were once again made available to provide an explanatory overview of the

Company filing and answer questions. At that conference, the judges requested that the parties state for the record their major areas of interest in the case.

Also discussed was the Company's stated intention to supplement its testimony on revenue decoupling at the update stage of the proceeding. The Company's initial filing addressed the issue of revenue decoupling, pursuant to the direction of the Commission in its Order Requiring Proposals for Revenue Decoupling Mechanisms, issued April 20, 2007, in Case Nos 03-E-0640 and 06-G-0746. However, since the order issued only two weeks before the Company's rate filing, the Company's testimony explained that it was presenting its principles for revenue decoupling but that it needed additional time to address the mechanics and other details of its proposal.[1]

4. Active Parties

In addition to the Company, the latest Active Party List in this proceeding lists the following parties: Department of Public Service Staff ("Staff"), New York State Consumer Protection Board ("CPB"), City of New York ("NYC") through the New York City Economic Development Corporation ("NYCEDC") and the Metropolitan Transportation Authority ("MTA"), County of Westchester ("Westchester"), New York Power Authority ("NYPA"), Natural Resources Defense Council ("NRDC"), Pace Energy Project ("Pace"), New York State Energy Research and Development Authority ("NYSERDA"), New York Energy Consumers Council, Inc. ("NYECC"), Utility Workers Union of America, AFL-CIO, Local 1-2 ("Local 1-2"), E Cubed Company, L.L.C. and Joint Supporters ("Joint Supporters"), Retail Energy Supply Association ("RESA"), Direct Energy Services, LLC ("Direct"), Small Customer Marketer

[1] Following the Procedural Conference and in order to enable Staff and other parties to respond to the Company's proposed mechanism in their direct testimonies, the Company agreed to provide these mechanics and details before filing its update and rebuttal testimony. The Company filed supplemental testimony providing additional details on the Company's revenue decoupling mechanism on July 13, 2007.

Coalition ("SCMC"), Consumer Power Advocates ("CPA"), ARE-East River Science Park, LLC ("ARE-ERSP"), Astoria Generating Company, LP ("AGC"), New York City Housing Authority ("NYCHA"), Energy Curtailment Specialists, Inc. ("ECS"), Consolidated Edison Solutions, Inc. ("CES"), Strategic Energy, LLC ("Strategic"), Senator Reverend Ruben Diaz, Central Hudson Gas & Electric Corp. ("Central Hudson"), Comverge, Inc. ("Comverge"), Constellation NewEnergy, LLC ("Constellation"), Cross Hudson Corporation ("Cross Hudson"), Energetix, Inc. ("Energetix"), Energywiz Inc. ("Energywiz"), EnerNOC, Inc. ("EnerNOC"), Hess Corporation ("Hess"), IDT Corporation ("IDT"), Independent Power Producers of New York, Inc. ("IPPNY"), Integrys Energy Services of New York, Inc. ("Integrys"), Itron, Liberty Power, National Energy Marketers Association ("NEMA"), New York City Council ("NYC Council"), NRG Energy, Inc. ("NRG"), Assemblyman Richard L. Brodsky, NYSEG/RG&E, Port Authority of NY & NJ ("Port Authority"), Public Utility Law Project ("PULP"), Reliant Energy, Inc. ("Reliant"), Science Applications International Corp. ("Science Applications"), Suez Energy North America, Inc. ("Suez"), U.S. Energy Savings Corp. ("USESC"), and Western Queens Power for the People Campaign ("WQPPC").

5. <u>Discovery</u>

During the course of discovery in this proceeding, the Company responded to over 1,100 interrogatories (the majority of which were multi-part) propounded by the various parties after the Company's rate filing on May 4, 2007. In connection with its preparations for rebuttal testimony and cross examination at hearings, the Company served more than 200 discovery requests on Staff and other parties.

6. Preliminary Accounting Update

In order to assist the parties in the preparation of their direct testimonies, the Company agreed to requests from Staff and other parties to provide a preliminary update to the proposed revenue requirement several weeks to a month before the date that the parties' direct testimony would be due. The Company provided this update on August 7, 2007. The update showed that the Company planned to reduce its proposed increase in revenue requirement by approximately $20 million, from $1.225 billion to $1.206 billion. This decrease reflected generally lower property taxes.

7. Testimony of Other Parties

On September 7, 2007, fifteen parties filed 33 pieces of testimony, plus numerous supporting exhibits, in response to Con Edison's electric rate filing. These parties included: Staff, NYC, Westchester, CPB, NYPA, NYECC, RESA/Direct Energy, CPA, Local 1-2, Joint Supporters, AGC, Pace/NRDC, ECS, NYCHA, and NYSERDA.

8. Rebuttal/Update Testimony

On September 28, 2007, the Company updated its rate filing, which reflected the preliminary update provided to the parties in August and additional updates based upon information that became available after August 7, 2007. The Company filed testimony explaining the updates and rebutting positions taken by Staff and other parties in opposition to various aspects of the Company's filing. Twenty-one Company witnesses submitted update and/or rebuttal testimony. Rebuttal testimony was also filed by three other parties: NYC, Staff, and Local 1-2.

9. Hearings

Hearings were conducted on eleven days between October 17, 2007, and October 31, 2007. Presiding over the hearings were Administrative Law Judges William Bouteiller, Michelle Phillips, and Rudy Stegemoeller.[2] The Judges were joined by Commissioner Robert E. Curry for the examination of certain witnesses. In addition to the Company, the following parties submitted appearances during the course of the hearings: Staff, CPB, NYC, Westchester, NYPA, NRDC, Pace, NYSERDA, NYECC, Local 1-2, Joint Supporters, RESA, SCMC, CPA, AGC, NYCHA, ECS, CES, and Strategic.

During the hearings, 20 Company witnesses, 11 Staff witnesses, and 10 witnesses for other parties were made available for cross examination. Among the other parties making witnesses available for cross examination were: NYC, NYPA, NYSERDA, CPB, NYECC, Westchester, and Local 1-2.

B. Overview of the Rate Request

The Company is seeking to increase its rates by $1.2 billion for the twelve-month period ending March 31, 2009 ("Rate Year").[3] The rate request is a function of two major elements:

- the Company's forecast of capital spending requirements necessary to maintain, replace and upgrade its electric transmission and distribution system and operation and maintenance ("O&M") expenditures for new programs designed to maintain and improve the quality, safety and reliability of the Company's electric service (approximately $685 million); and

- the impact of rate moderation measures that were used in setting rates in the Company's last electric rate proceeding (approximately $515 million).

[2] Administrative Law Judge Stegemoeller replaced Administrative Law Judge Elizabeth Liebschutz early in this proceeding.

[3] The Company's May 4, 2007 rate filing reflected a rate request of $1.225 billion. This amount was reduced to $1.2 billion in the Company's September 28, 2007 formal update.

1. Cost Drivers of Forecasted Expenditures and New Programs

For the reasons explained by the Company's witnesses, in particular, its Infrastructure Investment Panel, the Company must continue to make substantial and increasing investments to maintain, reinforce and upgrade its electric system to meet the growing needs of its customers and to provide the necessary funds to meet its financial obligations and maintain the Company's financial health and credit ratings. This includes:

- carrying costs on the approximately $6 billion that the Company is planning to invest in upgrading, reinforcing and replacing its electric infrastructure over the next three years (approximately $235 million of carrying costs in the first rate year);
- about $280 million in increased O&M expenses relating primarily to programs in support of its infrastructure;
- changes to depreciation rates and the recovery of the depreciation reserve deficiencies amounting to $100 million; and
- an increase of $115 million in the return to investors required to attract the necessary capital in the current environment.

Forecasted growth in electric sales is expected to partially offset these increases by $20 million.

In order to carry out this proposed infrastructure program, the Company expects to raise more than $3.5 billion of incremental funds in the financial markets in 2007 and 2008 alone. The proposed rate increase would enable Con Edison to maintain the financial strength and flexibility necessary to raise the capital it requires at a reasonable cost to consumers.

In addition, a major aspect of the Company's filing is a new program to promote demand side management ("DSM"), in light of heightened concerns over the environmental impacts of generation and increasing concern over global climate change. The Company's proposed DSM program to achieve at least 500 MW of demand reduction by 2016 is in furtherance of New York State, New York City, and Westchester County policies to pursue all available cost-effective

energy efficiency measures in order to reduce the environmental impacts of electricity, including Governor Spitzer's proposal to reduce energy consumption 15 percent by 2015, Mayor Bloomberg's goal of reducing greenhouse gases 30 percent from current levels by 2030, and Westchester County Executive Spano's formation of a climate change task force charged with producing a county-wide action plan to reduce greenhouse gas emissions and promote sustainable development.

The Company's program would provide multiple benefits to customers by reducing fossil-fuel generation emissions, such as CO_2, which result in global warming, and nitrous oxides, a major contributor to smog. And while difficult to quantify, the benefits from reducing customer demand can be expected to result in lower capacity prices, lower peak period energy prices, or both, which would translate to reductions in the energy portion of customer bills. Additionally, customers participating in selected programs will benefit directly through energy cost reductions

Investment in the Company's infrastructure will result in both immediate and long-term benefits to the Company's customers by enabling the Company to continue its record as the most reliable utility in the country. As is the case for other critical infrastructure that serves New York City and Westchester - roads, bridges, and water mains, to name a few - Con Edison's electric delivery system must be continually maintained, upgraded and, at times, replaced, so that it remains capable of providing the high levels of reliable electric service that customers have come to expect. In addition, the proposed rate increase would provide the necessary funding for new and ongoing programs that seek to support economic growth, improve public safety, enhance the quality of customer service, improve storm response, and pursue and implement advanced technologies.

In total, these forecasted increases in expenditures and operating costs from the levels established three years ago would result in a 7.3 percent increase in customer bills (or a 23.6 percent increase in delivery rates). However, this represents only approximately 63 percent of the rate request.

As explained in more detail below, the remaining portion of the rate request is attributable to the rate moderation measures that were used to set rates in the Company's last electric rate case. That is, even if the Company were not forecasting any increases in capital spending, proposing any new operating programs or forecasting material increases in various expenses, current rates must be adjusted upward, effective April 1, 2008, by approximately $515 million, to reflect the current costs that were approved in the last rate case.

2. Cost Drivers of Existing Rate Plan

The Company is currently operating under the terms of a Joint Proposal adopted by the Commission in Case No. 04-E-0572 ("2005 Rate Plan"). Order Adopting Three-Year Rate Plan, issued March 24, 2005 ("2005 Rate Plan Order"). The 2005 Rate Plan, which went into effect on April 1, 2005, provided for modest rate increases of $105 million and $220 million in the first and third years (*i.e.*, commencing April 1, 2005, and April 1, 2007, respectively). However, these rate increases were substantially understated. They relied upon the Company's retaining substantial customer credits in lieu of rate increases to fund a substantial portion of capital spending and increases in operating expenses. They also reflected less than the Company's forecasted level of capital spending.

As a result, all else being equal and as more specifically explained below, existing electric rates will be understated by approximately $515 million when the 2005 Rate Plan expires on March 31, 2008, of which approximately $250 million is attributable to deferred net

accounting credits and net cash proceeds from the sale of properties that will not continue after expiration of the 2005 Rate Plan; approximately $90 million is attributable to the recovery of deferred costs; and approximately $195 million is attributable to the inclusion of plant added to rate base above the level provided in the 2005 Rate Plan.

a) Use of Customer Credits to Mitigate Rate Request

The 2005 Rate Plan provided for the Company to retain various customer credits to mitigate the rate increase that would otherwise have been necessary to implement the cost of service underlying the rate plan. These credits are explicitly set forth on Appendix B to the 2005 Rate Plan. No party that participated in that proceeding or reviewed the rate plan document could reasonably claim surprise that a rate adjustment would be necessary for the twelve months ending March 31, 2009, to offset expiring credits.

As shown on Appendix B, under the column heading "RY3," the total amount of credits reflected in the rates for RY3 is $308 million. Of the amount, however, $60 million is attributable to annual proceeds from the auction of Transmission Congestion Contracts ("TCCs"), which the Company is proposing to continue to reflect in the revenue requirement for the Rate Year. Thus, the amount of "expiring credits" attributable to RY3 amounts to approximately $250 million.

Accordingly, there can be no question that electric rates must be increased effective April 1, 2008, by approximately $250 million to fill this gap, which is equivalent to approximately twenty percent of the requested rate increase.

b) Recovery of Deferred Costs

The second component of the existing rate plan that is driving a substantial portion of the rate request (approximately $90 million) is the recovery of certain costs recognized in the 2005

Rate Plan but for which base rates were not adjusted. Specifically, the Company needs to recover in the Rate Year:

- approximately $34 million of the deferred costs that are projected to accumulate by the end of the 2005 Rate Plan for World Trade Center expenditures;[4]
- approximately $66 million of the deferred carrying costs on T&D capital expenditures above the level included in rates during the third year of the 2005 Rate Plan;[5]
- an increase of approximately $100 million reflecting actual pension costs incurred during the 2005 Rate Plan above the level provided in rates; and
- a decrease of approximately $50 million for actual property taxes that were below the current rate allowance.

These net increased costs of approximately $150 million are partially offset by approximately $60 million of the credits remaining from the sale of the First Avenue properties and credits associated with federal and state income tax benefits that accumulated during the term of the 2005 Rate Plan.[6]

These adjustments account for approximately $90 million, or approximately 7.3 percent, of the requested rate increase.

c) <u>Capital Spending Targets</u>

The 2005 Rate Plan provided for a level of funding for capital projects less than the Company's forecast, reflecting instead an amount developed by trending the level of historic expenditures and projects actually achieved by the Company, and established a reconciliation

[4] As explained below, the Company is proposing to recover these O&M and capital interference costs over periods of three and thirty years, respectively. The total amount of deferred costs is $156 million (which includes $60 million that has been transferred to plant in service). The $34 million reflect the amount of these costs to be collected in the Rate Year.

[5] The deferred carrying charges for the third year are forecasted to be approximately $198.8 million, which the Company proposes to recover over a three-year period.

[6] The total amount of the credits are projected to be $180 million, which the Company proposes to pass back to customers over three years at the rate of $60 million per year.

mechanism for the Company to defer the carrying costs of capital expenditures above the targeted levels.[7]

While the capital expenditure reconciliation mechanism provided short term benefits to customers in that the carrying costs of plant above the target were deferred, this same mechanism is now placing upwards pressure on rates going forward.[8] That is, recovery of the deferred carrying costs for the third rate year and the delayed inclusion in rate base of amounts spent over the course of the 2005 Rate Plan reflect a significant portion of the rate increase that the Company is now seeking.

Specifically, during the first two years of the 2005 Rate Plan, the Company made capital expenditures of approximately $ 1.2 billion and $1.5 billion, respectively, and projects expenditures of approximately $1.7 billion in the final rate year. The Company is projecting that its average net plant balance for the third rate year of the 2005 Rate Plan will be $1.5 billion higher than the level included in rates.

As explained by the Company's Chief Financial Officer, Company witness Robert Hoglund, the Company needs cash to fund its capital expenditures and delayed recognition of capital expenditures in rates has put a tremendous strain on the Company's ability to raise and borrow money as well as maintain its credit rating.

The inclusion of plant added to rate base above the level provided in the 2005 Rate Plan accounts for approximately $195 million, or approximately sixteen percent, of the requested rate increase.

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[7] As explained below, the 2005 Rate Plan also included a regulatory oversight provision that required the Company to submit annually comprehensive reports as to its actual and forecasted capital expenditures for each year of the rate plan.

[8] As indicated above, the Company projects that it will have deferred carrying costs on plant for RY3 of $198.8 million at the end of the third rate year. The 2005 Rate Plan also provided for the Company to offset deferred carrying charges for RY1 and RY2 (which amounted to $60.0 million and $138.7 million, respectively) by utilizing available credits.

3. **Overall Reaction of Other Parties**

The proposed adjustments to the Company's rate request vary widely. For example, Staff proposes that the Company be granted an increase of $642 million, while Westchester proposes that increase be limited to $184 million. Other parties (*e.g.*, NYC) propose that rates be capped at some unstated level (while also proposing various approaches to allocating costs among the Company's customer groups).

As discussed in more detail below, while Staff's recommendations were driven by detailed analysis of the Company's projected expenditures and forecasted costs and expenses, the recommendations of many other parties were primarily driven by the magnitude of the rate request and the resulting impact on customers.

In addition, although several parties raised general concern with the magnitude of the Company's capital spending levels during the 2005 Rate Plan, no party identified any capital project that should not have been undertaken by the Company, and no party takes issue with the need to adjust the Company's electric rates to reflect expiring credits, the recovery of deferred costs or additional carrying charges attributable to the capital spending under the 2005 Rate Plan (other than Westchester's tacit rejection of these adjustments by proposing a rate increase limited to $184 million and proposals by some parties to amortize the recovery of some of those deferred costs over a longer period than the three years proposed by the Company).

As Company witness Mr. Rasmussen explained, the impact on future electric rates of expiring credits, the recovery of deferred costs and the increase in the Company's average net plant balance were well known to all parties to the prior proceeding, which are essentially the same parties to this case, and to the Commission itself. Westchester's statement that a reduction in the requested increase from $1.225 billion to $184 million "can be accomplished without harm

to the Company, its ratepayers, or the reliability of the system" (5445) is not only irresponsible but highly disingenuous. For example, its statement that "the Company received a rate increase at roughly the rate of inflation while at the same time it was able to invest over $3 billion in Transmission and Distribution Plant" (5446) blatantly ignores the fact that the modest rate increases reflected in the 2005 Rate Plan were made possible only through deferral of a large portion of the required rate increase in this proceeding via the use of customer credits, deferred accounting and a reconciliation mechanism implemented in connection with a consciously understated capital forecast.

As to the impact on customer bills, the Company explained that while it shared other parties' concern with the impact of its request on customer bills, and that it is not its preference to request an increase of this magnitude, the Company determined that the level of the increase requested could not be avoided, as it reflects the Company's best judgment as to the programs necessary for it to maintain the safety and reliability of its electric service. Nor would it serve the long-term interests of either customers or investors if the Company failed to address the major costs represented in the revenue requirement. The Company submitted voluminous testimony demonstrating that each of the programs proposed by the Company are necessary to support economic growth in the Company's service territory, maintain or improve reliability, meet safety and environmental requirements, meet various Commission mandates, and modernize its aging infrastructure, among other important objectives.

As stated by Mr. Rasmussen:

> The Company has been explaining for the last several years the fact that the load is growing and that there is a need to invest in infrastructure. In fact, one need only listen to the news to see that throughout the Country the infrastructure needs upgrading. Bridges fall, water mains break and roads cave in. All around us the infrastructure needs to be upgraded. Con Edison is trying to get out in front and upgrade its infrastructure, from building new substations to refurbishing

> transmission lines to adding new feeders to removing the rear end lot poles, [sic] the Company is working hard to invest in its facilities and upgrade them so that we are ready to serve for New York's needs, today and tomorrow. (2458).

Moreover, the rate request reflects material increases in costs that the Commission recognizes as being outside the Company's control, in particular, property taxes and pension/OPEB costs. While the protests to the rate request were laced with allegations as to the already high level of the Company's electric rates as compared to the rates of other electric utilities, the reasons for these high levels are a direct reflection of the environment in which the Company operates. People who live and/or work in New York recognize and accept that New York is a high cost area. They bear some of these high costs directly and others indirectly, through utility rates and the rates for other services to which they subscribe. (5110). At the same time, while electric rates may be higher when compared to the rates of other utilities, due to various factors including the nature of the Company's service territory (5113), electric bills are, on average, lower than in other parts of the country.

It also bears emphasis that a material portion of these higher costs are government-imposed. For example, New York City and Westchester property and other taxes make up about $1 billion of the Company's rate structure, accounting for more than 20 percent of the cost of electric service to customers. (Exh. 84, Sch. 1, p. 6). Yet, notwithstanding Westchester's very broad and conclusory statements as to the Company's current rates and the potential impact of the rate request, the Westchester Panel acknowledged that in formulating their recommendations they did not even consider asking Westchester County to forgo, even in part, the additional property and sales taxes it stands to receive from the Company's request. (5490).

While the Company disagrees with many of its proposed adjustments, Staff took the correct approach in undertaking a comprehensive evaluation of the Company's proposed

programs, based upon the Company's comprehensive testimonial presentation, as supplemented by detailed workpapers and extensive additional information provided by the Company's response to over 1,000 discovery requests. The Commission should give no weight to the requests of other parties that did not undertake such analyses but nonetheless call for arbitrary and global reductions in projected capital and O&M spending levels. The Commission's processes provide all parties with a full opportunity to examine the Company's proposed spending levels, and there is no basis for NYC's claim that "[i]t is very difficult for interveners, and even DPS Staff, to analyze a utility's Capital and O&M budgets and recommend elimination of specific projects." (4500).

Clearly, the Staff Infrastructure Panel was of a different view, stating "[o]ur review of the Company's work papers and responses to our interrogatories regarding O&M program costs demonstrate that the costs are necessary and appropriate" (4065) and "[w]ithout analyzing the underlying causes for the increased [capital] budget, including major project and program changes, Westchester's proposal is not reasonable in that it does not ensure customers will be provided with both safe and reliable service." (4066-4067).

Nor should the Commission countenance CPB's attempt to reject various Company O&M programs by claiming in its testimony that it was not provided with adequate information in response to its discovery requests. As the record amply demonstrates, not only did CPB raise not a single objection to the quality of the Company's responses to its discovery requests prior to the submission of its testimony (or thereafter, for that matter), and not only has CPB failed to identify specific credible deficiencies in the Company's responses, instead making broad and unsupported claims of deficiencies, CPB received copies of the very same responses that Staff

testifies adequately explained the reasons and nature of the Company's proposed programs. (4065).

Finally, while the Company recognizes that various matters at issue in this proceeding go to the timing of the Company's recovery of certain costs, as opposed to its right to recover such costs, the Commission must give serious consideration to the cash flow implications and impacts on future rates of long term amortizations. The transition from the 2005 Rate Plan is ample evidence that bill impacts to customers are delayed, but not avoided, when rates do not reflect the Company's current costs.

For the foregoing reasons and the reasons hereafter set forth in this Brief, the Commission should adopt the entirety of the Company's one-year rate request as proposed, or its alternative three-year rate plan proposal, including the rate adjustments necessary to address the impact on rates of the expiration of the 2005 Rate Plan.

II. RATE BASE

A. Capital Expenditures

1. Transmission and Distribution

a) The Company's Presentation

Con Edison's Infrastructure Investment Panel ("the IIP") – John F. Miksad, Senior Vice President – Electric Operations and William Longhi, Senior Vice President – Central Operations – presented Con Edison's transmission and distribution ("T&D") capital-expenditure requirements for the years 2008 through 2010.[9] (1699-1895; 1898-2041; Exhs. 120-140). The IIP addressed the Company's overall need for capital investment in T&D infrastructure during this period. (1701-1708). The IIP's overview of the Company's service area and its T&D system

[9] The IIP presented the Company's capital programs and projects on a calendar-year basis that is consistent with the Company's budget for these expenditures.

demonstrated that continual focus on both day-to-day operations and planned investments is essential for maintaining the safe and reliable electric service that is "critical for both the economic growth of the region and the health and well being" of over nine million people in New York City and Westchester County. (1703-1704). The T&D system is experiencing increased capacity requirements because of sustained economic growth and, at the same time, significant portions of the T&D infrastructure is aging and must be maintained, restored, and programmatically replaced. For example, 81 percent of the underground transmission feeders currently average 41 years of service and use technology (dielectric fluid-filled steel pipe) first deployed over 60 years ago. (1704-1705). The average age of the 33,300 miles of overhead distribution cable is about 40 years, and the average age of the Company's 91,000 miles of underground distribution cable is over 24 years (primary cable) and over 37 years (secondary cable). (1706-1707).

The sheer bulk of the distribution system in terms of the amount of facilities and equipment that must be maintained, expanded, and renovated is a dominating factor in establishing Con Edison's requirements for infrastructure investment. The distribution system consists of 76 secondary networks and load areas supplied from 57 area substations. The underground portion of the system is comprised of 262,700 manholes and service boxes and 25,500 transformers interconnected by 23,700 conduit miles of duct containing about 91,000 miles of cable. The overhead portion of the system is comprised of 46,650 transformers and 33,300 miles of cable supported on 205,000 poles. (1706-1707). These facilities and equipment supply about 40 percent of New York State's peak electricity demand.

The Company organizations responsible for the operation of the T&D system are Substation Operations (area and switching substations), Electric Operations (the underground

and overhead distribution system), and System and Transmission Operations ("S&TO") (transmission system and energy control center). The IIP presented the Company's T&D capital program and project requirements for each of these three organizations in the following six categories – each reflecting an essential component of the Company's responsibility for providing safe and reliable service:

- Support Economic Growth – projects required to meet the forecasted increase in customer demand. This includes projects associated with generation interconnections.

- Improve System Reliability – projects designed to maintain and improve the reliability of the Company's transmission and distribution infrastructure both in the near and long term.

- Public Safety and Environmental Improvements – projects aimed at reducing the probability of an event endangering the safety of the public or an event that adversely affects the environment.

- Storm Hardening and Response - projects designed to make the Con Edison system more storm resistant, shorten the duration of storm related outages and improve communication to customers and other stakeholders during a storm event.

- Advanced Technology – projects utilizing cutting-edge technology to enhance operating and engineering models of the system, in order to make timely decisions to improve reliability.

- Process Improvement – projects designed to streamline processes and improve efficiency. (1702-1703).

The IIP presented capital programs and projects under these categories in the total amount of $1,834.8 million in 2008 and $1,771.9 million in 2009, equating to rate year expenditures of $1,819.1 million.[10]

(i) <u>Support Economic Growth</u>

[10] The capital costs discussed in this Brief reflect the costs presented in IIP's updated filing. (1989-1918, Exhs. 130-133). The Rate Year revenue requirement reflects a blend of capital costs for 2008 (nine months) and 2009 (three months).

The total electric demand in Con Edison's service territory continues to grow at approximately 1.5 percent per year. Against a base load of about 13,000 megawatts ("MW") in 2007, this equates to load growth of about 1,000 MWs over the five year period through 2012. (1710, Exh. 120, p. 1). The Company's filing in this proceeding reflects support of the energy issues recently cited in the Governor's and Mayor's future energy plans. Electricity use has increased more than 20 percent over the past 10 years, and the Company is responding with a two-fold approach. As discussed in more detail in the Demand Side Management/Energy Efficiency section of this Brief, the Company proposes energy efficiency measures which will help slow the rising demand for power. At the same time, the Company needs to increase investments in order to maintain a reliable, resilient, and robust infrastructure necessary to meet the needs of a growing population and an increasing demand for electricity. Con Edison's capital program provides for the increased substation, transmission, and distribution infrastructure necessary to support existing and expected new load growth.

(a) Substation Operations

Con Edison's 58 area substations supply the electric demand of Con Edison's 78 load areas up to the design capacity of the substations' transformers.[11] (1706). The Company takes a variety of actions (load relief measures) to maximize the ability of its substations to supply customer demand without the construction of costly new substations. These measures include installing transformers, capacitors, and transformer cooling equipment to maximize substation output, transferring electric load from substations near or at capacity to nearby substations with "spare" capacity, and focusing demand side management programs in targeted areas to defer the need for substation construction. (1710-1711). Inevitably, however, load growth reduces

[11] The number of Company substations and load areas have increased since the Company's initial filing in May 2007.

available margins of unused substation capacity to the point where there is no alternative other than to construct new area substations in sufficient time to meet projected load growth. Exhibit 120, pp. 3 and 4 shows the ongoing loss in area substation capacity margin from 2006 through 2011 even with the implementation of the load relief measures contemplated by the Company's current capital construction plan. (1711).

Con Edison's switching substations transfer bulk electric power from generation sources to the Company's area substations. Similar to the process described above, growing demand from area substations reduces the unused capacity of switching stations. In these cases, the Company takes actions to maximize switching station capacity, such as connection of new generation supply, installation of phase angle regulators and series reactors, and load transfers (1726), but inevitably new switching stations must be built in time to supply projected load growth.

In 2008, Con Edison projects capital expenditures of $453.3 million for the construction of eleven area and switching substations and the addition of capacity at existing substations. In 2009, Con Edison projects capital expenditures of $409.53 million for substation construction and capacity additions. (1712-1727; 1900-1911; Exh. 130, p. 1).

(b) System and Transmission Operations

The 885 MW Poletti Generating Station currently supports the growing load in Con Edison's East 13th Street load pocket. The retirement of the station in 2010 will require replacement of this generating capacity. Con Edison expects to reconfigure the existing feeders Q35 L & M connecting the Poletti Station to the East 13th Street Switching Station to install a new 345 kV connection between the existing feeders and one or both Astoria Switching Stations

to connect to the generation resources supplying those switching stations. The costs of this project in 2008 and 2009 will be about $36.4 and $54.6 million, respectively. (1735-1736; Exh. 132).

System and Transmission Operations will also continue its program to install dynamic feeder rating systems on selected feeders to more accurately calculate feeder loading capability at a cost of $1 million in each of 2008 and 2009. (1736; Exh. 132).

(c) Electric Operations (Distribution System)

To address load growth on the distribution system resulting from increased consumption of electricity and the addition of new customers during 2008 and 2009, Con Edison's Electric Operations Organization will install, reinforce, and upgrade primary network feeder cables, network transformers, underground secondary cable, non-network primary and secondary cables and wires, non-network transformers, and underground and overhead services and will transfer load between networks in the distribution system to relieve potential overloads. Capital expenditures for this work will be about $339.5 million in 2008 and $336.5 million in 2009. This consists of area substation relief ($48.6 and $48.2 million in 2008 and 2009, respectively), unit substation relief ($6.4 million each year), reinforcement of primary feeders and secondary cable ($59.4 and $57.8 million, respectively), infrastructure additions to connect new customers ($144.3 and $142.7 million, respectively), and related purchases of transformers ($69.2 million each year) and meters ($11.9 and $12.3 million, respectively). (1737-1741; Exh. 133, p. 1).

(ii) <u>Improve System Reliability</u>

Con Edison is consistently recognized as one of the most reliable utilities in the United States. To maintain this high level of reliability, the Company places significant emphasis on programs/projects that maintain the operational capability of the substation, transmission, and

distribution systems. To do this, the Company both addresses near-term issues that have been identified and programmatically and continuously upgrades or replaces aging system components before they become degraded, obsolete, or no longer supported by manufacturers with spare parts and technical support.

(a) Substation Operations

Most of Con Edison's 37 switching stations and 58 area substations are over 40 years old. The capital funding for reliability work provides for the programmatic replacement and/or upgrade of major components such as circuit breakers (345 kV, 138 kV, 33 kV, 27 kV, and 13 kV), disconnect switches and circuit switchers, protective relay equipment, communication equipment, battery systems, transformers and miscellaneous equipment, such as potential/current transformers, insulators, surge arresters, and wiring, before they become degraded or obsolete. Funding is also provided for maintaining the physical structures (substation building, relay houses/cabinets, and switchgear houses) that house the electrical components of a substation. (1746-1747).

In total, capital expenditures to improve substation reliability will be about $140.9 million in 2008 and $142.1 million in 2009. This includes $57 million in 2008 and $76.3 million in 2009 for major substation equipment, such as circuit breakers, obsolete transformers, and spare transformers (1747-1752; 1911-1912; Exh. 130, p. 2); $12 million and $5.5 million in 2008 and 2009, respectively, to address obsolete and problematic substation relay components and add functionality (1753-1756, Exh. 130, p. 2); and $61.9 million and $60.3 million in 2008 and 2009, respectively, for miscellaneous substation components, such as alarm panels, feeder test devices, batteries, remote terminal units, capacitor cables, roofs and facility upgrades, and technology improvements. (1756-1772; Exh. 130, p. 2).

(b) System and Transmission Operations

System and Transmission Operations will undertake a variety of capital projects, costing $185.1 million in 2008 and $139.3 million in 2009, to maintain and improve the reliability of the transmission system. The major project in this program, one that that will both enhance reliability and provide load support, is the construction of 345 kV Feeder M29 and the Academy switching substation with projected expenditures of $143 million and $73 million in 2008 and 2009, respectively. A variety of smaller projects will enhance transmission system reliability by replacing aged feeders that are experiencing operational problems, replacing failed cable sections, upgrading transmission towers, and installing a phase angle regulator to replace switching station feeder power-flow control when the Poletti Generating Station is retired. (1781-1789, Exh. 132).

(c) Electric Operations (Distribution System)

Electric Operations undertakes a variety of programs to maintain and improve the reliability of the network distribution system. These programs are supported by databases that track performance and reliability, and load flow models that help the Company prioritize electric distribution investment. These databases and models are used to identify potential reliability problems and predict how particular reliability improvement schemes might mitigate these problems. This analysis is performed following each summer period in order that the Company may complete any necessary upgrades and/or repairs prior to the following summer peak load period. Distribution reliability work consists of repair of failed equipment and proactive replacement and upgrade of system components. (1796-1797).

The principal programs for primary system reliability are continued replacement of paper insulated lead-covered ("PILC") cable, including the removal of associated stop joints,

replacement and relief of targeted network transformers, performing high potential feeder tests, repair and reinforcement of primary feeders, and SF_6 sectionalizing switch installation. (1798 - 1803). Electric Operations maintains and improves the reliability of the secondary network system by replacing failed secondary mains; reducing the backlog of unrepaired mains on the system; installing and upgrading secondary mains to relieve projected overloads; and proactively replacing aging cable infrastructure through the Underground Secondary Reliability program. (1804-1805). The distribution system reliability program also includes programs to modernize the Company's 217 distribution ("unit") substations, most of which are over 40 years old, by replacing and/or upgrading major components such as switchgear (circuit breakers), tap changer position indicators, protective relay equipment, as well as addressing automation and supervisory control before these components become degraded or obsolete. Equally important is addressing the physical structures (substation foundations, concrete pads, roofs, etc.) of the distribution substations themselves. (1806-1811).

Electric Operations' capital expenditures for distribution system reliability will total about $533.8 million in 2008 and $528 million in 2009. (Exh. 133, p. 1).

(iii) <u>Public Safety and Environmental Improvements</u>

(a) Electric Operations Public Safety

Con Edison strives to ensure the safety of both the public and our employees, and the Company has undertaken a number of programs to improve the safety of electric service in New York City and Westchester County. For example, the public safety programs associated with stray voltage have reduced the number of shocks attributable to the Company facilities by 58

percent as compared with 2004 events. These positive results stem from the Company's aggressive and multifaceted approach to improve safety.

The Company's Electric Operations capital investments for the distribution system in 2008 and 2009 support these public safety initiatives with programs addressing ventilation of combustible manhole gasses, reduction of transformer ruptures, and safety of street lights (stray voltage isolation transformers). Electric Operations will spend $20.9 million in 2008 and $11.8 million in 2009 on these programs. (Exh. 133, p. 2).

(iv) <u>Environmental Improvements</u>

Con Edison maintains high standards regarding environmental reporting and compliance. Innovest Strategic Value Advisors ranked Consolidated Edison, Inc. second out of 27 international utilities in environmental and social performance in a new 2007 Multi-Utilities & Unregulated Power index created by the investment advisory firm. The Company has made strides in this area and intends to continue to improve. (1823).

(a) Substation Operations Environmental Improvements

The capital funding for Substation Operations environmental programs focus on the identification, reduction, and mitigation of dielectric fluid and oil leaks at and from substations and feeder pressurizing and cooling plants into the facility and into waterways and permeable surfaces nearby. These programs prioritize facilities by risk; implement containment and control methods; install leak detection systems; and upgrade equipment including pumps, pump controls, alarm panels, and recorders. Substation Operations will spend $13.5 million in 2008 and $13 million in 2009 on these programs. (1823-1828; Exh. 130, p. 2).

(b) System and Transmission Operations Environmental Improvements

Con Edison has been the industry leader in developing new techniques for detecting and locating dielectric fluid leaks on pipe-type cables and has substantially reduced dielectric fluid loss to the environment over the past decade. In 2008 and 2009, System and Transmission Operations will complete a New York State Department of Environmental Conservation Consent Order program for the installation of stop joints on feeders that cross waterways to minimize the loss of dielectric fluid in case the feeder pipe develops a major leak in the submarine section. The estimated expenditures for this program are $1.75 million for each of 2008 and 2009. The Company's Environmental Enhancements project investigates and implements new leak detection technologies for transmission feeders. Two promising leak detection systems are being developed, which the Company anticipates installing on its transmission feeders in future years. (1829-1830; Exh. 132).

(c) Electric Operations Environmental Improvements

The distribution system oil minders program provides for the environmental integrity of network transformer vaults by installing oil minders that reduce the risk of oil entering the municipal sewer system. The program targets 300 installations per year at a cost of $600,000 annually. (1937; Exh. 133, p. 2).

(v) <u>Overhead Distribution System Storm Hardening and Response</u>

Overhead cables, wires, and transformers are affected by exposure to weather, harsh operating environments, and wear and tear due to use and operations. In addition, severe weather can result in substantial damage to electrical equipment and widespread outages to customers. This is exemplified by the three major storms that struck Con Edison's service area,

particularly Westchester County, in 2006. Electric Operations will implement or continue over twenty capital programs that are designed to enhance the robustness and resilience of the overhead distribution system to make it less prone to equipment failure during adverse weather. These programs also include considerable upgrades and modernization of the overhead, non-network system.

Many of these programs replace obsolete switches and switching systems with automated switching schemes and devices that will isolate faults more effectively and rapidly reducing customer outage durations. Increasing the automation of these switches will allow the grid to "self-heal" with minimal operator intervention, while providing feeder intelligence back to our operating control centers. This will allow more effective allocation of resources and dispatch of first responders. (1836-1839).

The installation of modern Kyle switches and SCADA monitoring and remote control equipment will enhance the Company's ability to more rapidly isolate the effects of damaged equipment to smaller numbers of customers. The replacement of aging, faulty gang switches, mainly in Westchester, will also facilitate switching and isolation of faulted equipment to more rapidly restore customers to service. The sectionalizing of 4 kV and 13 kV feeders using reclosers, gang operating switches, and air break switches allows isolation of the sectionalized portion for repair and restoration of the rest of the feeder and customers to service. The splitting of seven overhead auto-loop feeders and the installation of two new auto-loops in Brooklyn and Queens will reduce the number of customers potentially affected by an outage. The replacement of Okonite cable, No. 4 and No. 6 self-supporting wire, and overhead feeder components that are the leading causes of failures will decrease customer outages, reduce outage durations, and

reliability. Capital expenditures for storm hardening and response programs total $44.2 million in 2008 and $46.7 million in 2009. (1834-1845; Exh. 133, p. 2).

(vi) <u>Advanced Technology</u>

Advanced technology allows the Company to better manage the operation of the transmission and distribution systems. The Company uses the latest technologies to streamline processes and improve performance, reliability, efficiency, and safety. (1858-1859).

(a) System and Transmission Operations

Exhibit 136, "System and Transmission Operations Capital Projects," addresses expenditures related to the operation of the electric system at Con Edison's Energy Control Center ("ECC").[12] The Company's electric generation, transmission, and distribution systems, as well as the steam system, are controlled from the ECC. (1859). The System Operation Capital Programs shown on Exhibit 136 address the systems and processes used at the ECC to manage the electric system and are intended to provide the operators with comprehensive, accurate, and up to date system and related information at all times. (1859-1860). The IIP presented the System Operation Capital Program in the Advanced Technology section of its testimony.

The monitoring and control capabilities of the Energy Management System ("EMS") provide Control Center Bulk Power and District operators the ability to safely and effectively monitor and operate the Company's electric system. EMS also provides many applications and tools that support advanced real-time analysis of system conditions, warning alarms for actual and possible contingencies, interfaces to the NYISO for operational needs, load shedding,

[12] The Company's IIP presented two separate exhibits for System and Transmission Operations capital expenditures. Exhibit 132, "Transmission Operations Capital Projects / Programs," discussed previously, addresses expenditures related to the construction and reinforcement of the transmission system. Exhibit 136, "System and Transmission Operations Capital Projects," addresses expenditures related to the operation of the electric system at Con Edison's Energy Control Center.

voltage reduction, and rapid restoration capabilities. (1860). The System Operation Capital Program includes funds to complete the installation of a new integrated transmission and distribution EMS, including full system redundancy at both the primary and backup ECCs and upgraded remote terminal unit functionality to improve substation and feeder information and control at the ECC. In addition, Operations Management Systems, which manages distribution and transmission feeder operations, as well as operation of telephone lines used for relay protection of the transmission system, will be upgraded with analytical tools and tracking and recording functionalities. Power supplies, lighting systems, HVAC and emergency generation at the ECC will be upgraded. The costs of these capital projects will be $14.9 million in 2008 and $11.3 million in 2009. (1859-1870; Exh. 136).

(b) Electric Operations (Distribution System)

Electric Operations is developing and implementing technological projects to improve the performance of the distribution system. The development and deployment of adaptive business intelligence software will assist in designing new processes that drive out inefficiencies and reduce risks. This analysis software will merge with the traditional power flow and reliability analyses currently utilized to provide strategy optimization and decision support for the evaluation of operations and planning designs and procedures, such as the optimal deployment of electrical assets to meet peak electric demand and the potential measurement and enablement of curtailable load. The Secondary Network Visualization Model will provide operators a dynamic, visual picture of the state of the secondary network to readily recognize a deteriorating or improving condition in the network and facilitate decisions prior to the actual event. A four-year program to upgrade the Company's four Electric Distribution Control Centers will address required system architecture and communications network. The Mapping

System upgrade project will consolidate the multiple existing corporate mapping applications into a single, standard, digital data model; converting existing land-base maps to "real-world" coordinate system maps (as used by New York City and Westchester County); and registering the existing electric distribution equipment data onto these maps. Electric Operations capital expenditures for these and other advanced technology projects will be $41.1 million in 2008 and $37.5 million in 2009. (1880-1887; Exh. 133, p. 2).

(vii) <u>Process Improvement</u>

Electric Operations will implement five initiatives specifically aimed at improving efficiency. In 2009, Electric Operations will initiate work on a comprehensive Work Management System, which will track work and time spent into a common, corporate-wide platform for budgeting, planning, acquiring, scheduling, and tracking use of resources. The Energy Services organization within Electric Operations maintains relationships with customers. To facilitate these relationships and improve customer service, the entire workflow in Energy Services will be modernized, including communication platforms, wireless field system, GPS field sheets, and digital filing. A new Mobile Dispatch tool in Electric Construction will track work crews by GPS, dispatch work to crew vehicles, and capture work completion data at the work location via a wireless communication system. In addition, Electric Operations will develop accounting for cost by network and will provide support for wireless services.

Capital expenditures for process improvements will be $3.5 million in 2008 and $16 million in 2009. (1887-1889; Exh. 133, p. 2).

(viii) <u>Security</u>

To enhance physical security and to bring all of substation facilities into compliance with the Company's security specification, Substation Operations plans to install physical security

systems consisting of closed circuit TV, monitoring, and access systems at six substations in 2008 and seven substations in 2009. The Company will also purchase "man down" radios for the substation in 2008 and 2009. Capital expenditures for this work will be $4.1 million in 2008 and in 2009. (Exh. 140, p. 2).

b) <u>Staff's Proposals</u>

The Staff Infrastructure Panel ("SIP") testified that "[o]verall, the electric infrastructure improvements are necessary. Economic growth has been gradually increasing, and the Company's aging transmission and distribution system justifies the need for significant targeted capital investment." (3995). The SIP also acknowledged that "electric demand has steadily increased … actual peak loads either reached or exceeded the company's 2002 projections at both the substation and network levels." (3995-3996). Further, in reviewing the Company's projected expenditures, the SIP did not reject any program or project as unjustified. Nonetheless, SIP recommends that Con Edison's Rate Year capital expenditures be reduced by $218 million. (Exh. 274).

For the most part, the SIP's review of the Company's capital expenditures follows the six categories in which the Company presented these expenditures, and the SIP proposes adjustments on a program-specific basis in the six categories. The Company's comments below on the SIP's proposed adjustments are presented in a similar manner. However, for System and Transmission Operations' capital programs, the SIP proposes a global adjustment that does not address any S&TO program specifically. We will address this global adjustment below in the end of this section of the Brief.

(i) <u>Support Economic Growth</u>

The Company's capital expenditures in support of economic growth consist of programs and projects for substations, the transmission system, and the distribution system construction and reinforcement. The SIP "reviewed and examined" each of the substation construction projects that will have cost effects in the rate year and concluded that "each of these projects is needed and justified." (4001-4004). The SIP also examined major rate-year distribution system projects, including distribution load relief projects associated with area substations, primary feeder relief work, underground network transformer installations and also concluded that "these projects are necessary." (4007-4010). The SIP proposed no specific adjustments for the substation and distribution projects that support economic growth. The SIP's adjustment for S&TO economic growth capital programs is subsumed in its global S&TO adjustment discussed at the end of this section.

(ii) <u>Improve System Reliability</u>

In the "Improve System Reliability" category, the SIP proposes adjustments to seven Substation Operations reliability programs/projects identified in Exhibit 130. These adjustments are reflected in Exhibit 274, p. 3 (Obsolete Transformers, Spare Transformers, Category Alarms, RTU Replacement, Substation Loss Contingency, Enhancing Reliability and Facility Improvements). The SIP also proposes adjustments to three Electric Operations reliability programs/projects identified in Exhibit 130. These adjustments are reflected in Exhibit 274, p. 6 (PILC, Network Transformers >100% <115%, and Transformer Purchase). The SIP's adjustment for S&TO reliability capital programs is subsumed in its global S&TO adjustment. The Company opposes each of Staff's twelve reliability program adjustments, as discussed below.

(a) Obsolete Transformers Replacement Program

Staff recommends a reduction in the 2008 budget for the Obsolete Transformer Program from $17.2 million to $15 million. Staff contends this reduction is justified based on historical under-spending of about $2 million/year for this program and the fact that the Company "only budgeted $10.3 million for this program in 2007." (4011-4012).

The replacement of obsolete equipment, such as system transformers, is critical to ensuring continued reliable service. (1934). The average age of the Company's 400 substation transformers is about 30 years, and the Company needs to replace ten transformers per year solely to maintain the current 30-year average age. The transformer replacement program is expensive – approximately $8 to $10 million per transformer. (2137). The Company's current program replaces an average of two transformers per year in recognition that the electric system presents many competing demands for investment of capital. (2125; 2135). Staff's proposal would impede the Company from achieving even this limited goal for replacing its most aged substation transformers.

The Company's estimated cash-flow requirement for this program is based on the specific scopes and replacement costs associated with ongoing and planned work to replace two transformers at the West 19th St. and Cherry St. Substations as well as to provide funding to initiate the purchase of transformers for future replacement projects. (1934). The funds provided for this important program should not be based on historical expenditures, particularly when the number of transformer replacements in past years has varied.[13] Thus, the $10.3 million budgeted for 2007 reflects the cost for one transformer replacement while the costs projected for 2008

[13] Company witness Longhi erred in stating that expenditures for the Obsolete Transformers program were $23 million in 2005 and $28 million in 2006. (2135). The Company's expenditures in those years were $3 million and $14.3 million. (Exh. 273, p. 2).

reflects two replacements plus transformer purchase for future replacements. (2135). Staff's proposed adjustment will hinder this important project and should be rejected.

(b) Spare Transformers Program

The SIP proposes that the Company's 2008 expected expenditures for spare transformers be reduced to $14 million. In addition, the SIP chose not to consider the Company's expenditure changes filed with the parties on August 7, 2007 and included in the Company's September 28, 2007 update filing, which increased the estimated cost of this program from $16.5 million to $21.2 million in 2008 and from $12 million to $33.7 million in 2009. (1912; 4012-4013; Exh. 122, p. 2; Exh. 130, p. 1). The SIP's downward adjustment to $14 million for 2008 was prompted by the decline in spending from $16.5 million to $12 million forecast in the Company's initial filing (Exh. 122, p. 2) and is based on the three-year 2008 to 2010 average ($13.5 million) for program spending reflected in the Company's initial filing. (Exh. 122, p. 2).[14]

The SIP's proposed $14 million allowance for 2008 falls far short of the $21.2 million expenditure required to adequately support the Spare Transformer Program in 2008. Since Con Edison's initial filing in May 2007, the Company's has initiated procurement of transformers to support a strategic increase in its spare transformer inventory. This action was based on a re-evaluation of the adequacy of the current spares inventory due to the continuing long lead times for major equipment and recent transformer failures at Rainey Substation (transformers 7W and 8W in December 2006 and mid-April 2007), which prompted the re-evaluation of the spare inventory strategy to insure a 90 percent confidence-level probability of spare availability in the event of a substation power transformer failure.[15] More recent failures at Jamaica (transformer

[14] As explained below, the SIP's adjustment to $14 million is entirely unwarranted. Nevertheless, it should be noted that Staff's adjustment to $14 million "that averages out future expenditures" (4013) is not carried forward to 2009 where the SIP proposes only $12 million. (Exh. 274, p. 3).
[15] The Company's Spare Transformer Probability analysis is contained in Exhibit 137. (1935-1936).

No. 4) and Dunwoodie (reactor No. 1) Substations reinforced the need for this re-evaluation. This resulted in a need to increase the spare transformer inventory by seven transformers to ensure adequate spares are available to respond to future failure scenarios. (Exh. 137). In addition, incremental funding is required to purchase replacement transformers for the spare units taken from inventory to replace the failed Rainey units. Further, recent dramatic increases in transformer costs for the basic materials required for manufacturing transformers and in response to the new New York City code requiring lower noise levels have contributed to the higher updated cost of this program. (1911-1912; 1935).

The SIP states that they declined to consider the Company's updated cost filing for the Spare Transformer program because the Company's response to Staff data request 498 "did not provide any new information pertaining to the rate year justifying the proposed expenditure increase, or adequately supplement information received in response to our prior information request, DPS-440." (4012-4013). Contrary to Staff's contention, however, the Company's response to DPS-498 did include a full justification for the cost increase. The response is contained in Exhibit 273, pp. 188-190. The response states that the recent transformer failure activity and increased transformer manufacturing lead times resulted in the amendment of the spare transformer retention policy and an increased inventory requirement. (Exh. 273). The response also mentioned the impact of recent cost increases in basic transformer materials. (*id.*) Further, the response also contained a summary of the costs of the seven additional spare transformers plus the effect of these purchases on 2008 through 2011 cash flow requirements. Finally, the response provided the costs to replace the two failed Rainey transformers. Given

this detail in the Company's response to DPS-498, the Company is puzzled by Staff's inability to find information justifying the updated costs.[16]

Con Edison has fully supported the costs of this program. Staff's adjustment should be denied, especially when the SIP testified that the Spare Transformer program is "justified." (4013). Reducing the projected costs of this program will reduce the confidence level below 90 percent expectation that a spare transformer will be immediately available spare in the event that one of the in-service transformers of a particular class fails. (1936-1937).

(c) Category Alarms Replacement Program

Staff proposes to reduce the funding for the replacement of Category Alarms from $2.25 million in 2008 to $1 million. Staff's explanation is that the Company has not spent budgeted amounts in the past, never spent more than $810,000, and did not explain why spending will increase. (4013-4014).

The Company's substation alarm equipment has been in service for an average of 40 years. Due to lack of spare parts and/or vendor support of system modifications, the Company has been replacing high maintenance units since the late 1990s at a rate of approximately two per year. But, since more panels are becoming obsolete, the Company is accelerating the replacement to four per year. This enhancement will improve the operational response to substation alarms. (1757).

The funding for this program needs to be increased not only because of the increase in the number of units per year to be replaced, but also because of the significant cost increase associated with replacing entire alarm panel systems. One of the scheduled replacements is the East 13th Street switching station alarm panel system. A switching station, by design, has a

[16] Additional information on the Spare Transformer inventory and the transformers on order was provided to Staff in response to DPS-440. (Exh 273, pp. 137-140).

higher number of alarm points than an area substation. The East 13th Street system incorporates 345kV and 138kV equipment at the East River Complex and will require extensive conduit and fiber optic installations. Three other alarm panels will also be replaced in the near term -- Brownsville and Goethals switching substations and Washington Street area substation. For the longer term, 11 alarm panels that have frequent repair issues or are difficult to repair/maintain due to parts availability will be prioritized and replaced under this program. (1952).

Having found that the Category Alarm program is justified, the SIP's adjustment based on historical spending levels is flawed. As demonstrated by the Company, the historical expenditure levels do not accurately reflect the need for expenses associated with the future requirements of this program. The Company has amply demonstrated why spending on this program will increase in the Rate Year. Staff's adjustment should be rejected.

(d) Remote Terminal Unit Replacement

The SIP proposed to reduce funding for the replacement of substation Remote Terminal Units ("RTU") from $3 million to $2 million in 2008 and from $4 million to $2 million in 2009. While Staff found that this program is justified, Staff asserts that past expenditures do not support the Company's projected expenditures.[17] (4014). Once again, Staff's adjustment based on historical expenditure levels is unjustified because historic expenditures do not accurately reflect the need or expenses associated with the future requirements of the program.

The RTUs at the various substations enable the remote supervision of the electric system from the ECC and are the key links for transmitting critical operational data between each transmission switching substation and the ECC. Each RTU continuously monitors and controls each substation circuit breaker, motorized disconnect switch, phase angle regulator, transformer,

[17] Although Staff states that 2007 expenditures are unknown, Staff's Exhibit 273, page 153, shows that, through July 2007, the Company had spent over half ($507,000) of the 2007 budget ($1 million) for RTU replacement.

and telemetering of each feeder. The original 1970's vintage SOCCS RTUs were installed in that decade and are now reaching the end of their useful lives. Spare parts are no longer readily available and, as a result, the ability to maintain these critical components is compromised. (1761-1762; 1959).

The recent installation of the Company's new Energy Management System has underscored the need to upgrade the RTUs throughout the system. The replacement of the existing RTUs with new technology will support communication with multiple systems and will provide system expansion capability. The existing RTUs work on an old communication protocol that is not directly compatible with the communication protocols used with the new EMS, limit the speed of data transmission to long-obsolete 1200-baud modems, and prohibit communication with other advanced substation devices. While interim modified communication kits allow the RTUs to communicate with the new EMS and the ECC, the supervisory and control capabilities of the substations cannot be expanded without a full replacement of the RTUs, and the expansion of the new EMS will be encumbered delaying realization of its full capabilities. (1960).

In addition, the replacement of the existing RTUs as planned will improve system security since the selection of an open architectural communication protocol as the standard protocol for the system will support the Company's compliance with the NERC Cyber Security Standard. (1960).

For all of these reasons -- to resolve obsolescence and reliability issues, to support the modern communications protocols that will be used by the EMS, and to enhance cyber security of the transmission system -- the Company plans to replace the RTUs at all 38 transmission

stations on an expedited basis over the next three years. The Company has fully supported its planned expenditures for this program in the Rate Year. Staff's adjustment should be rejected.

(e) Substation Loss Contingency Program

The SIP concedes that this program is justified, but recommends reducing the program from $2 million to $1 million for each of 2008 and 2009 based on low levels of historical expenditures. (4014-4015). Although past activity for this program has largely involved planning, the program has now matured to the point where significant expenditures are required for implementation.

This important program prepares for the loss of any one of a number of selected 345 kV, 138 kV, or 69 kV transmission switching substations. The planning and procurement of spare equipment in advance of a substation loss will enable more rapid restoration of these critical transmission points in the electric system. The Company has developed restoration plans for the individual loss of one of several switching substations, and plans have now matured to the point that equipment and engineering packages required to support these contingency plans have been specifically identified. Funding of $2 million in 2008 and in 2009 is necessary to procure this equipment and develop the engineering packages. (1961-1962). The Company's response to Staff's interrogatory 489 identified the specific labor and equipment funding requirements for this program in 2008 and 2009. (Exh. 139, pp. 22-23). Staff's proposed adjustment will extend the time necessary to complete this important initiative and should be denied.

(f) Enhancing Substation Reliability Program

The SIP proposes to reduce funding for the Company's program to enhance substation reliability from $12.5 million in 2008 and in 2009 to $10 million in each year. Staff argues that the $12.5 million funding proposal for this program exceeds the Company's $7.75 million

expenditure in 2006 and the Company's 2007 budget for this program was only $6.1 million. (4015).

Staff's analysis of the Enhancing Substation Reliability program is seriously flawed. Staff's expenditure analysis addresses the expenditures for only one of four projects within this program. When expenditures for all four projects are considered, the Company's 2008 and 2009 funding requests are supported.

The four projects in the Enhancing Substation Reliability program and their proposed expenditure levels in each of 2008 and 2009 are as follows: Area Substation Reliability ($8.5 million), Fire Protection ($0.5 million), Capacitor Cable Upgrade Program ($3 million), and Reinforced Ground Grid ($0.5 million). Thus, the Company proposes to spend a total of $12.5 million in each of 2008 and 2009 for the four projects. (1767-1769; Exh. 121, pp. 2-3; Exh. 130, p. 2).

Inexplicably, the SIP testimony addresses only the expenditures for the Area Substation Reliability project.[18] Thus, while the Company's expenditure of $7.75 million for the Area Reliability project in 2006, cited by the SIP (4015), supports the funding of $8.5 million for this one project, Staff erroneously cites the $7.75 million expenditure as covering all four projects within the Enhancing Substation Reliability program. Staff does not challenge the 2008 and 2009 funding for the other three projects. Accordingly, Staff's adjustment is in error and should be denied.

(g) Facility Improvement (Upgrade) Program

[18] The SIP refers to the Company's response to Staff's data requests DPS 124 and 145. Both of these data request responses clearly refer only to the Area Reliability project. The response to DPS 145 (Exh. 273, pp. 23-24) specifically discussed the $8.5 million budget for this project.

The SIP proposes to entirely eliminate funding for the Company's Facility Upgrade Program because "this program appears to be redundant with the Company's Small Capital Program" and "projects in this category [are] more appropriately placed in other programs." Staff suspects "double counting" and asserts that the Company provided no historical spending or budget data for this program. (4015-4016).

The Company's Facility Upgrade program funds a wide range of important large-scale facility construction and upgrades, such as permanent work locations for employees working out of temporary office trailers; structural improvements to façades, foundations, retaining walls, lifts and platforms, floors, heating and ventilation, lighting, and plumbing; and large-scale drainage modifications, paving and fencing. The scope of the Facilities Upgrade program is intentionally broad and encompassing to allow funding of larger scale projects not covered by other capital programs. (1771-1772; 1953; Exh. 130, p. 2).

The SIP erroneously suspects that the Small Capital and the Facility Improvement programs are redundant. However, each of these programs funds discretely different projects that are differentiated by the size/cost of the respective project. The candidate project list for the Small Capital program was provided in response to Staff data request DPS-145. (Exh. 273, pp. 23-30). Each of the 37 projects identified in this list is estimated to cost less than $500,000 to complete. In comparison, the Facility Improvement project list, provided in response to Staff data request DPS-489, identifies over 30 projects each of which is estimated to cost $500,000 or more. (Exh. 139, pp. 13-19). None of the Facility Improvement projects listed are redundant with the Company's Small Capital Program or any other defined scope capital program. (1956-1957).

Moreover, notwithstanding that the SIP states that "the Company provided no historical spending or budget data for this area" (4016), the Company provided to Staff historical data for the Facility Upgrade program dating from 2002 to 2006 in response to Staff data request DPS-125 (Exh. 139, pp. 1-2), showing expenditures in each year.[19] The present candidate project list provided to Staff lists over $30 million of planned and proposed projects for the next three years to correct and upgrade numerous age-related structural and facility issues, as well as to transition personnel from temporary trailers to permanent facilities, in order to ensure safe and reliable operation of the substations. The Company recognizes that it would not be reasonable to take on all of these facility improvement projects within the 2008 to 2010 period and intends to prioritize these projects to fit within the established level of $6,000,000 per year in funding as an ongoing program. Clearly, however, the extensive amount of Facility Improvement program work identified clearly indicates the need and provides sufficient basis for the requested funding of this program. Additionally, the magnitude of scope and overall cost of this program prohibits these projects from being absorbed by other capital programs that lack sufficient funding to adequately address the identified issues. (1957-1958).

Staff contends that two projects for the Facility Upgrade program, the fire protection system improvements at Dunwoodie and the modifications of the Parkchester area substation to accommodate new high voltage test set facilities, are redundant since there are other capital programs to address these projects. (4016). Contrary to Staff's position, building modifications to accommodate the addition of a high voltage test set at the Parkchester Substation are beyond the scope of the proposed High Voltage Test Set program. The Company's response to Staff data request DPS-145 clearly delineates that the funds for the High Voltage Test Set program are

[19] Staff's Exhibit 139, pp. 1-2, does not include the Company's supplemental response to the DPS-125 showing expenditures of $5.9 million and $1.6 million for this program in 2002 and 2003, respectively.

meant for the purchase and/or replacement of equipment, and not for facility improvements to accommodate this equipment. The Parkchester facility project, which will allow installation of an additional DC test set, is estimated to cost $500,000. The High Voltage Test Set program provides funding totaling $500,000/year for the purchase of three DC high voltage test sets.[20] Thus, utilizing the High Voltage Test Set program budget for the Parkchester facility project would prevent or delay the needed replacement of three DC high voltage test sets at other locations. (1955).

In addition, while Staff claims that the Dunwoodie Station fire protection system water supply line and deluge house replacement project could be placed in a transmission capital program, the fact is that it is placed in the Facility Upgrade program, which is available for switching substations such as Dunwoodie, and the expenditures are not redundant with any other capital program. Staff may have expected to see the Dunwoodie project under the Fire Protection program (Exh. 130, p. 2), which is another Substation Operations capital program, but the scope of the Fire Protection capital program is well-defined and limited solely to the modification of existing fire protection piping to allow system testing in accordance with NFPA and New York City codes and regulations. The program is funded at $500,000/year to support the completion of modifications at six substations per year. The Dunwoodie facility improvement project alone is estimated to cost $1,500,000. Clearly, the Fire Protection program is not adequately funded to support this project or any other fire protection related project outside of the narrowly defined scope of that program. (1956).

[20] The High Voltage Test Sets program provides funding of $6.5 million in 2008 and $2 million in 2009. This program funds the purchase of three fixed and three mobile low frequency AC test sets and two transmission voltage level test set, in addition to three distribution voltage level DC test sets per year. (1758-1760; Exh. 273, pp. 26-28).

(h) Paper-In-Lead-Covered ("PILC") Cable

The Company proposed to increase its current expenditures for the removal of PILC cable from $23 million to $39 million per year so that the Company could target an additional 900 sections of PILC cable for removal in 2008 and 2009 in order to accelerate its target for the removal of all PILC cable from the distribution system from 2024 to 2020. (1798-1799; 1928). The SIP "recommend[s] a $9 million reduction to more appropriately reflect the increased number of PILC sections to be removed each year." (4023). It is not clear whether Staff believes that the Company will be able to remove 900 additional sections with the $7 million funding increase that Staff proposes, or that Staff believes that the Company will fall short of its 900 sections goal and the $7 million is about what the Company will actually spend for additional removals in 2008. Further, while the SIP indicates in its rebuttal to Mr. Koda's testimony that that Staff has provided a "proposed rate of removals" in this case (4062), it is unclear what removal rate Staff is expecting for the removal cost that Staff proposes in this proceeding.

It costs the Company, on average, about $18,000 to remove a section of PILC cable. Staff has provided no basis for assuming a different average cost. Accordingly, should the Commission determine that incremental funding for this effort be less than the $16 million proposed by the Company, the Commission must also acknowledge that the number of PILC sections to be removed will be reduced accordingly.

Significantly, Staff asserts that the Company's performance in removing PILC cable has not been acceptable, but offers no evidence to support this assertion. (4023). Since 1999, the Company has been engaged in a program to remove PILC cable and thermally sensitive stop joints. That program has resulted in the removal of nearly half of the PILC cable from the distribution system. The Company's program has improved feeder performance, established highly reliable key feeders in a network, and eliminated thermally sensitive stop joints. Staff's

assertion that the Company has made "minimal effort" and that the Company's performance is "not acceptable" is misleading and unfounded. (1929-1930).

(i) Network Transformer Relief >100% and <115%

The Company plans to spend $92.9 million in 2008 to relieve network transformers that are projected to operate beyond their contingency ratings. The Company relieves transformers in following three tiers (2008 cost for each tier included): (1) transformers projected to operate at greater than 125 percent of contingency rating ($15.5 million); (2) transformers projected to operate at greater than 115 percent and less than 125 percent of contingency rating ($25.9 million); and (3) transformers projected to operate at greater than 100 percent and less than 115 percent of contingency rating ($51.4 million). The relief of each tier includes installing new transformers, reconnecting existing transformers to different feeders, replacement of transformer network protectors, and the reinforcement of associated secondary mains. The costs stated above do not include the cost of replacement transformers. (1803; Exh. 133. p. 1).

The SIP recommends no adjustment for the costs of the tier one and tier two programs. However, the SIP proposes that the budgeted amount for the tier three program be reduced by 50 percent, from $51.4 million to $25.7 million. (4021-4022). Con Edison opposes Staff's adjustment.

Relieving network transformers that are projected to operate beyond their contingency ratings will improve both network reliability and extend the service life of network transformers. (1803). While the Company has focused this program on the higher priority transformers in tiers one and two, the Company now wants to begin addressing the deferred tier-three overloaded

transformers to obtain these same benefits.[21] The Company believes it should not defer the relief of these transformers indefinitely. (1933). Thus, the Company is adding eight design technicians, 20 underground cable splicers, 20 installation and apparatus splicers, 25 cable-pulling mechanics, as well as additional supervisors, to support this program. (1804). The point here is not whether the number of higher priority overloads have declined, as Staff appears to argue. (4022). Rather, the point is that the Company is establishing the resources required to begin to address tier-three transformer overloads, in addition to the tier-one and tier-two transformers that it has focused on previously. Staff's adjustment will serve to further delay the relief of tier-three transformers.

(j) Transformer Purchase

Con Edison has budgeted $66 million in 2008 and in 2009 for purchase of network transformers that are installed on its network system for all purposes, including transformer relief (tiers one, two, and three), load growth, failures, and replacements, *e.g.*, corroded transformers. (Exh. 133, p. 1). With the intent of adjusting the transformer-purchase budget only, to reflect Staff's adjustment for tier-three transformer relief, the SIP proposes to reduce the overall funding for transformer purchases from $66 million to $31.2 million (4022; Exh. 274, p. 6). However, the effect of Staff's adjustment is to cut into the funding for the purchase of transformers installed for reasons other than tier-three relief.

Company witness Miksad explained that the Company projects the replacement of 274 tier-three transformers, assuming the full funding of $51.4 million. Staff's proposed reduction to $25.7 million would allow for the replacement of only about 137 tier-three transformers. To be

[21] In support of its adjustment, the SIP asserts that Con Edison "has provided no record of historical spending for replacement of transformers operating between 100 and 115 percent." (4022). Staff should draw no adverse inference. The Company has previously not budgeted this category of overloads for relief. (1933).

consistent, Staff's transformer-purchase adjustment should have similarly removed the purchase cost for 137 transformers for the tier-three program, *i.e.*, about $7.5 million, reflecting a unit cost of about $56,000 for a transformer and its network protector. (5425-5426). Staff's adjustment of $34.8 million is unsupported and unjustified and should be rejected.

(iii) <u>Public Safety and Environmental</u>

In the "Public Safety and Environmental" category, the SIP proposes adjustments to two Substation Operations environmental programs/projects identified in the Company's Exhibit 130. These adjustments are reflected in the SIP's Exhibit 274, p. 3 (Pumping Plant Improvement and Environmental Risk).

The SIP also proposes adjustments to two Electric Operations public safety and environmental programs/projects identified in the Company's Exhibit 133, p. 2. These adjustments are reflected in the SIP's Exhibit 274, p. 6 (Oil Minders and Vented Manhole Cover). The SIP's adjustment for the S&TO environmental program is subsumed in its global S&TO adjustment discussed below. The Company opposes each of Staff's four public safety and environmental program adjustments, as discussed below.

(a) Pumping Plant Improvement

The SIP proposes to reduce funding for the Pumping Plant Improvement program from the $8.5 million to $5 million. As also discussed in the section immediately below, the SIP also proposes to decrease the Environmental Risk program from $3.5 million to $2 million. (4027). This represents a total decrease of $5 million per year from Substation Operations' overall funding requirement in the Environmental category of $13.5 million (a 37 percent reduction) in

2008 and $13 million (a 38.5 percent reduction) in 2009.[22] Staff's sole justification for these substantial adjustments is its assertion that the Company's actual expenditures under the Environmental category between 2004 and 2006, as shown in the Company's response to Staff data request DPS 466 (Exh. 273, pp. 142, 153-154), were not aligned with budgeted amounts. (4027).

A review of the data provided by the Company in response to DPS-466 (Exh. 273, pp. 142, 153-154) shows that between 2004 and 2006, the total budgeted amount for the Environmental category was $34,695,000, and the actual amount expended was $33,968,000, or an average of $11.3 million per year. The total difference of $727,000 between budgeted and actual expenditures represents an average difference of only two percent, or $243,000 per year, over the 3-year period. A 2 percent difference between budget and actual expenditures is insignificant and certainly does not warrant Staff's 37 percent and 38 percent annual adjustments. The $5 million per year reduction proposed by Staff would actually decrease the level of funding available for this important category of programs by $2.8 million per year below historical expenditure levels.

As described by the Company's IIP, Pumping Plant Improvement is a continuing program consisting of both pumping and cooling plant replacements and upgrades. There are 36 circulating plants on 345 kV and 138 kV transmission feeders, most of which are over 30 years old. The older plants have oil leaks, and aged equipment that is no longer supported by the equipment manufacturer, making it difficult to obtain replacement parts. There are 39 existing PURS cooling plants on 345 kV Feeders. None of these cooling plants have pump speed control capability, which controls power consumption during light feeder loads and periods of cooler

[22] Substation Operations' funding requirement for environmental programs also includes two other programs, estimated to cost $1.5 million in 2008 and $1 million in 2009, which the SIP does not adjust.

ambient temperatures. Also, the annunciator panels have become unreliable and are no longer supported by the vendor. (1826).

The circulating pump upgrade program replaces older pumps, pump controls, alarm panels, and chart recorders, making the plants more reliable and eliminating environmental leaks from the pumps. The cooling plants upgrade program includes replacing existing motor control centers with new ones and replacing old control panels with state-of-the-art control panels. The pump house and circulating plant alarm panel upgrade program will replace control and alarm panels at various plants and includes the replacement of chart recorders, pressure gauges, and alarm panels. In addition, a Leak Detection System ("LDS") will be installed for 345kV Feeders M54 and M55. (1826-1827). The Company's response to Staff interrogatory 422 (Exh. 138, pp. 3-6) provides the scope of the planned $8.5 million annual expenditures for Pumping Plant Improvements program (p. 3), as well as the location of the future projects (p. 4) and cost detail about past pumping plant improvement work. (pp. 5-6). The Company's IIP identified 14 circulating plant and skid replacement projects, totaling $15.2 million; seven pumping plant feeder control projects, totaling $7 million; and four circulating plant upgrades, totaling $0.8 million. (1940).

The SIP's testimony does not dispute the importance of this program. Staff's analysis is based solely on historical spending levels and is flawed. Staff's proposed $3.5 million adjustment for this program should be rejected.

(b) Environmental Risk

The SIP proposes to decrease the Environmental Risk program from the $3.5 million proposed by the Company to $2 million. As discussed above, Staff's sole justification for this substantial adjustment is its assertion that the Company's actual expenditures under the

Environmental category between 2004 and 2006, as shown in the Company's response to Staff DPS 466 (Exh. 273, pp. 142, 153-154), were not aligned with budgeted amounts. (4027). As explained above, there is only a two percent difference, and a two percent variance between the Company's historical budgets and actual spending clearly does not support Staff's proposed 43 percent adjustment for this program.

In the Environmental Risk Program, the Substation Operations Risk Management Team performs risk assessments to identify substations that have a potential for serious environmental impact in the event a major incident causes the release of dielectric fluid to the environment. The team performs detailed reviews of each substation's drainage drawings and evaluates the topography of each site. To minimize the potential environmental impact, the team recommends various containment and control methods, including the installation of oil/water separator systems and drain modifications. (1824). The Company's proposal for this program is based on specific programs at specific substations to be implemented in 2008. The Company's response to Staff 351 identifies containment and control projects for three substations to be undertaken in 2008 at a cost of $3.6 million, and additional projects for three more substations to be undertaken in 2008 at a cost of 3.75 million. (Exh. 138, pp. 1-2).

The SIP's testimony does not dispute the need for, or the merits of, this program. Its analysis is based only on historical spending levels and is flawed. Staff's proposed $1.5 million adjustment for this $3.5 million program should be rejected.

(c) Oil Minders

The SIP does not oppose the Company's Oil Minder program, but proposes that funding be reduced from $600,000 to $500,000 because of prior expenditure shortfalls compared to budgets. (4028; Exh. 274, p. 6). The distribution system oil minders program provides for the

environmental integrity of network transformer vaults by installing oil minders that reduce the risk of oil entering the municipal sewer system. The funding reduction will result in an installation target of 250 units, instead of the 300 units that were included in the Company's submission, and will increase the length of time to complete this program. (1937).

(d) Vented Manhole Cover

The SIP proposes to reduce funding for the installation of vented manhole covers from $8 million in 2008 to $3 million. (4025-4026; Exh. 274, p. 6). Replacing solid manhole covers with vented covers allows ventilation of combustible gases that will mitigate the severity of manhole events. (1937). Con Edison developed and has been installing vented covers on its manholes in a four-year program that is scheduled to finish in 2008. (1817-1818; Exh. 133, p. 2). Staff's funding reduction for this program will slow the replacement of both standard and non-standard covers by one year, whereas the goal is to expeditiously replace these covers and improve public safety. (1937-1938).

In support of its adjustment, the SIP, referring to the Company's response to Staff interrogatories 302 and 458 (Exh. 273, pp. 33-34, 141), cites the "planning, work, uncertainty, and time required to complete the remaining non-standard covers." (4026). Nowhere in the Company's response to these data requests does the Company indicate any uncertainty about the timing for the completion of this program in 2008. As stated in the Company's response to DPS-302, about 10,000 of the Company's 62,508 manholes require non-standard vented covers that the Company is developing. (Exh. 273, p. 33). The Company has already installed over 40,500 standard vented manhole covers in 2005 and 2006 at a combined cost of $16 million (Exh. 273, pp. 33-34, 141) and plans to install the remaining 12,000 vented standard covers and 10,000 non-standard vented covers in 2007 and 2008. Staff has provided no analysis based on past expenditures or otherwise

that the Company will not complete this program in 2008, or that the $8 million funding level for this program in 2008 is not warranted. Staff's adjustment should be denied.

(e) Street Light Isolation Transformers

Con Edison will install isolation transformers in the base of about 130,000 metallic streetlights in New York City over four years to reduce the incidence of stray voltage associated with streetlights by up to 78 percent. An isolation transformer ("IT"), connected at the base of a streetlight, eliminates the hazard of stray voltage from phase or neutral wire failure by providing an isolated loop that prevents the flow of current from the energized streetlight structure to ground through a different path, such as through human or animal contact with the streetlight surface. (1820-1821; Exh. 273, p. 35).

Con Edison has already installed about 3,600 ITs in New York City street light bases in a pilot project coordinated with the New York City Department of Transportation ("DOT"). The DOT supports Con Edison's installation of ITs in its existing streetlight pole bases. Further, because the DOT provides for the ordinary maintenance and replacement of streetlight poles, DOT has agreed to install ITs in new streetlights, maintain all installed ITs, and, when necessary, replace ITs from an IT stock to be purchased and maintained by Con Edison. (1821-1822).

The Company's Rate Panel describes changes to the Company's PASNY tariff regarding street lighting associated with the installation and maintenance of the ITs.

Staff found this program to be justified, and recommended that the Company's proposed funding be made available. However, the SIP recommended that that the ITs be installed in the Company's service boxes, not in street light bases, and that the Company be responsible for maintaining the ITs. In support of its recommendation, Staff refers to the Company's response

to Staff data request DPS 494, which lists the advantages and disadvantages of installing the ITs in the street light bases. (4025; Exh. 273, pp. 178-179).

Installation of ITs in the service boxes will likely provide full protection from stray voltage conditions that result from equipment failure on Con Edison's secondary system. Installation in the street light base will protect against only about 78 percent of such conditions. However, several factors offset this advantage of service box installations. First, as part of the IT installation in the street light base, the existing bonding strap in the street light foundation will be removed. This will provide additional, though not complete, protection from failed secondary equipment. Second, because ITs have a 600 watt limit, street lights could no longer be used as sources of temporary power, *e.g.*, for street fairs and holiday lighting, which would overload the IT and extinguish the street light. A temporary bypass of the IT would require assignment of already limited Company resources to access the service box before and after the temporary use. Third, street light bases are readily accessible for IT installations such that Company workers could install about 10 ITs per day, versus about only 4 ITs per day for service box installations. Thus, service box installations would require more than doubling the IT installation program to 8 years, or a 2.25 times increase in the allocation of limited manpower resources. Finally, service box installation requires the use of more specialized and trained underground splicers rather than Mechanic A workers. (Exh. 272, pp. 178-179).

Assuming that IT's are installed in the street light base, the Company does not believe that it should be responsible for the maintenance of the units, given DOT's agreement to undertake this activity as an adjunct to its ordinary maintenance and repair of its street lights.

While the Company understands Staff's concerns, the Company believes that, overall, IT installations in the street light base is preferable.

(iv) Storm Hardening and Response

In the "Storm Hardening and Response" category, the SIP proposes adjustments to 11 Electric Operations programs/projects identified in the Company's Exhibit 133. These adjustments are reflected in the SIP's Exhibit 274, p. 6 (Osmose (C Truss), Autoloop Reliability, No. 4 and No. 6 Self Supporting Wire, 3 Phase Gang Switch Replacement, Overhead Feeder Reliability, Rear-Lot Pole Elimination, Enhanced 4kV Grid Monitoring, 4 kV Underground Reliability, Overhead Secondary Reliability Program, ATS Installation USS reliability XW, and Transformer Purchase.)[23]

(a) Osmose (C Truss)

Staff recommends a funding reduction from $1.7 million to $1.3 million for the C-Truss program, based on the inaccurate statement that "the Company has forecasted a rejection rate for poles that is above the actual historical rejection rate." (4029-4030; Exh. 274, p. 6).

The C Truss program reduces the inspection cycle for overhead poles from a 12-year cycle to a 10-year cycle in order to enhance the reliability of poles and safety to the public. Any poles identified during the pole inspection as requiring attention will either be replaced or restored to full strength – and functionality – by way of "C-Trussing." (1836). The Company's capital funding of $1.7 million is composed of two parts: 1) the C-trussing of an estimated seven percent of the inspected pole population, and 2) the capital portion for replacing approximately one percent of the inspected poles due to rejection that cannot be corrected though C-trussing. The seven percent rejection rate is taken from a 2003 engineering study of 11 years of pole

[23] Con Edison did not present Storm Hardening and Response programs or projects for Substation Operations and S&TO.

inspections from 1992-2002. The one percent pole replacement rate is a conservative estimate derived from a rejection rate of 1.3 percent experienced during the 2004 inspection of 8,841 poles in Queens, with 117 of them determined to be non-restorable poles. (1943).

In contrast, Staff calculated its recommended reduction based only on the C-truss work component of this program. Apparently because Staff believes that the seven percent pole rejection rate used in the Company's estimate is higher than historical levels (Staff does not indicate what it believes historical levels to be), Staff uses the Company's 2006 expenditures for C-trussing as the basis for its proposal. (4029-4030). Staff's recommendation should be rejected. Staff's calculation does not reflect the pole replacement component of the program (1942-1943), and Staff provides no support for its conclusion that the Company's seven percent rejection rate is not reasonable.

(b) Autoloop Reliability

The SIP recommends a funding reduction from $7.9 million to $6 million for the Autoloop Reliability program. (Exh. 274, p. 6). Staff asserts that the Company's actual historical expense was lower than budgeted, and recommends adjustments by splitting the difference between the average actual expense and the Company's proposed funding. (4030-4031).

The Company's program is driven by its specifications requiring the installation of particular types of autoloops based on feeder loading. (1944). Under Staff's proposal, autoloops that have or are developing loads greater than allowed by specifications will not be addressed, thereby, falling out of compliance with specification and jeopardizing service reliability to customers. (1943-1944).

(c) No. 4 and No. 6 Self Supporting Wire

The SIP recommends a $1.11 million reduction in funding for the No. 4 and No. 6 Self Supporting Wire program from $3.4 million to $2.3 million in 2008, and from $3.3 million to $2.3 million in 2009. Again, Staff asserts that the Company's actual historical expense was lower than budgeted, and recommends an adjustment to split the difference between the average actual expense and the Company's proposed funding level. (4030-4031).

The Company's funding requirement is a conservative estimate for several reasons. It reflects a cost estimate of $11.46/ ft for 1/0 Aluminum, the smallest and least expensive cable. The program also uses heavier, more expensive 2/0 Cu, 4/0 Al, and 477Al cable. (1944). Given that load growth on the overhead feeders results in the larger branches of the feeder becoming overloaded first, with the radial spurs experiencing overload conditions last, the reconductoring plan provides for reconductoring the larger main runs first. (1944). Thus, it is likely that heavier, more expensive cable will be used in 2008 and the per foot cost estimate included in the Company's filing is low. In addition, the estimated cable footage was derived from only the primary 4kV and 13kV conductors (three conductors per span), and does not take into account the system neutral that should be at equal or greater capacity to the primary conductors. (1945). The result is a possible increase of up to 33 percent to the total reconductoring footage. (i*d.*). In short, the Company's estimate is already conservative and a further funding reduction to this program will unjustifiably lengthen the duration of this cable replacement program.

(d) 3 Phase Gang Switch Replacement

The SIP incorrectly asserts that the Company plans to replace defective switches based on an estimated amount of old and mechanically deficient devices. (4031; Exh. 274, p. 6). The Company plans to replace these switches using a proactive approach to replacement, not just replacing defective switches. (1946). Thus, Staff's $100,000 adjustment based on an estimated historical replacement of gang switches does not reflect the Company's approach to this program. The Company's 20 percent replacement rate is a conservative estimate derived based on a recent inspection of approximately 100 gang switches in Brooklyn-Queens that yielded closer to a 35 percent rate. (1945-1946).

(e) Overhead Feeder Reliability

The SIP adjusts Overhead Feeder Reliability by $300,000, from $750,000 to $450,000 for 2009 funding. (Exh. 274, p. 6). Other than identifying the adjustment in their exhibit, Staff neither mentions nor explains the adjustment. This adjustment should be rejected for, among other things, lack of support.

(f) Rear-Lot Pole Elimination

Staff dismissed the importance of the Rear-Lot Pole elimination program by deeming the program to be "non-essential," and, therefore, recommended a $1.2 million reduction (50 percent) to funding for the program. (4032; Exh. 274, p. 6). This program is essential for several reasons. First, loading on rear-lot secondary lines has dramatically increased, but the Company has only a limited ability to reinforce these lines from a secondary or tertiary location. (1946). Some rear-lot secondary has reached capacity with no options for installing a conductor upgrade. (1947). The result is an increase in failures on rear-lot secondary lines. Second, repairs of failed rear-lot secondary have required re-conductoring of multiple spans. (1946). Such Company expenditures for repair and upgrade of an obsolete system are not cost effective. (*id.*). Third, the

entry into limited-access rear lots can present safety concerns for the Company's emergency response personnel, such as reduced clearances to power lines, installed appurtenances, overgrown conditions and limited illuminations. Difficulty in gaining access has resulted in prolonged customer outages and prevented routine maintenance of our facilities. (1844, 1946-1947).

Thus, the 50 percent reduction recommended by Staff would, if continued, stretch the program from 20 years to 40 years, further straining an already overloaded system. (1947). Staff's recommendation should be rejected.

(g) Enhanced 4kV Grid Monitoring

The SIP adjusts funding for Enhanced 4kV Grid Monitoring by $500,000, from $1.5 million to $1 million, for 2008, and by $1.5 million, from $2.5 million to $1 million, for 2009. (Exh. 274, p. 6). Staff asserts that the Company has not provided adequate support for its proposed funding levels and questions an increase from a prior budget estimate of $450,000. (4032-4033).[24]

The Company's response to Staff's interrogatory 368 provided sufficient basis for the Company's estimated funding for this program (Exh. 273, pp. 106-107). For work being performed in 2007, the cost quote for the initial five unit substations was $182,000 to furnish hardware, software, and to supervise installation. Additional funds for installation labor, overheads and contingency amounted to $68,000, for a total of $250,000. This equates to a unit cost of $50,000 per station.

For years 2008 and beyond, the estimated cost based on a vendor quote is $26,500 per station. Estimated cost for installation labor, overheads, and contingency per substation is

[24] The SIP cites the Company's response to Staff 466 in support of this prior $450,000 budget estimate. (4032). The Company's response to DPS-466 (Exh. 153) contains no such budget estimate.

$15,350, yielding a total cost per unit substation of $41,850. The Company plans to install these advance power quality meters and battery monitoring systems in 35 unit substations ($1.5 million) in 2008 and in 60 unit substations ($2.5 million) in 2009. (1947-1948; Exh. 273, pp. 106-107).

Staff's proposed reduction will prevent the Company from deploying this technology in all of its 240 4kV Unit Substations by the end of 2011, as planned. Staff's adjustment should be rejected. (1948).

(h) 4 kV Underground Reliability

The SIP adjusts 4kV Underground Reliability program by $700,000, from $1.3 million to $600,000, for each of 2008 and 2009. (4033; Exh 274, p. 6). Staff incorrectly believes that the replacement rate is based on a 62 percent failure rate. (4033).

Risers are critical infrastructure, and their failures affect 33,000 customers annually. (1949). Each riser failure interrupts 100 percent of the customers on that feeder, unless the feeder is equipped with a midpoint device such as an ESCO or Kyle switch that limits the interruption to approximately 50 percent of the customers on the feeder. The Company has experienced an average of 23.4 riser failures annually over the last five years. With 743 in-service risers on the system, the failure rate is 3.15 percent per year. (1948-1949).

Riser failures are the result of cable, termination, and joint failures. Prior to this program, repairs were made when possible, and cable was replaced when necessary. This program will replace the cable on risers that fail and will replace the cable on risers that previously failed and were repaired. (1949).

The Company's projected cost of this program reflects replacement of 31 risers per year, at an average cost of $42,000 per riser. This projection covers the replacement of the average

number of risers that fail each year plus the replacement of additional risers. Over the expected 15-year duration of this program, the Company expects that about 62 percent of the risers of the system will be replaced. (1950).

Staff's adjustment will substantially slow the progress of this program to make the 4 kV system more resistant to failure and should be rejected.

(i) Overhead Secondary Reliability Program

The Company does not contest Staff's adjustment for the Overhead Secondary Reliability Program.

(j) ATS Installation USS reliability XW

The SIP adjusts ATS Installation USS reliability XW by $1.4 million from $2.45 million to $1.05 million for 2009 funding. (Exh. 274, p. 6). Other than to identify the adjustment in its exhibit, the SIP neither mentions nor explains the adjustment. This adjustment should be rejected for lack of support, among other reasons.

(k) Transformer Purchase

The SIP adjusts the Transformer Purchase program by $500,000 from $8.56 million to $8 million for each of 2008 and 2009. (4034; Exh. 274, p. 6). Staff's proposal to reduce the funding for transformers used for storm response is based on Staff's view that the uncertainty in the number of storm events each year provides latitude to reduce the purchase of these transformers. However, Staff's adjustment is ill-advised because having sufficient replacement equipment, including transformers, is essential for the Company's response to emergencies and the ability to maintain or restore electric service to customers during emergencies. (1950). Staff's adjustment should be rejected.

(v) Advanced Technology

In the "Advanced Technology" category, the SIP proposes adjustments to three Electric Operations programs/projects identified in Exhibit 133. These adjustments are reflected in Exhibit 274, p. 4 (Secondary Visualization Model, Distribution Control Center Upgrades, and SCADA Systems).[25] The Company also presented Advanced Technology Projects for S&TO in Exhibit 136 ("System Operations Capital Programs"). The SIP's adjustment for S&TO Advanced Technology Programs is subsumed in its global S&TO adjustment discussed below.

(a) Secondary Visualization Model

The SIP adjusts funding for the Secondary Visualization Model program by $1.5 million, from $5.2 million to $3.7 million, for 2008 and by $300,000, from $4 million to $3.7 million, for 2009. Looking at the Company's projected expenditures for 2008 through 2010, Staff is skeptical of the Company's higher dollar amount projected for the first year of the program. Accordingly, Staff proposed to levelize the cost of this program by averaging the projected expenditures for 2008 through 2010. (4035-4036; Exh. 274, p. 4).

In order to model the load flows on the secondary network grid and develop the secondary load flow models, the Company has developed a five-step process that focuses on the secondary network mapping data extraction, mapping connectivity, cable specifications, secondary demand estimation, and demand reconciliation. (1963).

To effectively model the secondary network load flows, it is imperative that the secondary network mapping data are accurate and fully connected. These first two steps ensure

[25] Con Edison did not present Advanced Technology programs or projects for Substation Operations. The Company presented Advanced Technology Projects for S&TO in Exhibit 136 ("System Operations Capital Programs').

that the secondary network model is an actual representation of the field conditions and all changes resulting from the work completed in the field are accurately reflected in the model. The Company has developed automated processes to extract the mapping data and check for connectivity. Prior to initiating the remaining steps for the networks targeted each year for secondary modeling completion, all errors in the mapping data have to be resolved. (1963).

Mapping error resolution is a labor-intensive process and the Company has been automating all the correction processes to the extent possible. The Company plans to address system-wide secondary mapping errors by retaining additional contractor resources during 2008, which is the primary driver behind higher dollar allocation to the first year of the program. (1963-1964).

Staff's proposal to use a three-year average of the projected expenditures will adversely impact the progress of the program and the ability of the Company to timely complete the secondary models for the networks targeted for completion during each year of the program. Staff's proposal should be denied.

(b) Distribution Control Center Upgrades

The SIP adjusts the proposed $5 million funding in 2008 for Distribution Control Center Upgrades by $2.3 million. Looking at the Company's projected expenditures for 2008 through 2010, Staff is concerned by the Company's higher dollar amount projected for the first year of the program. Accordingly, Staff proposed to levelize the cost of this program by averaging the projected expenditures for 2008 through 2010. (4035-4036; Exh. 274, p. 4).[26]

The Distribution Control Centers, which are regional operating authorities that command and control the safe and reliable operation of the electric distribution system, must remain up to

[26] Staff's averaging methodology would seemingly require that the Company's expenditure for 2009 be increased from $2.5 million to $2.67 million. However, Staff does not propose such an upward adjustment.

date with current technology. The Company, as a whole, maintains over 134,000 remote monitoring points requiring computer technology, communications, system integration modules, hardware and software that are constantly evolving for speed, reliability, and accuracy. The Distribution Control Center Upgrade program updates the Company's Electric Control Centers with current software and technology and improves their performance with new operating tools. (1966).

The Company disagrees with Staff's proposed $2.3 million reduction and believes the program funding for $5 million should be maintained. Staff's proposal is based solely on historical spending, which is not always an appropriate indicator of future spending, and fails to consider the potential consequences of delay in supporting technology deployment in critical areas of power delivery systems. (1967).

(c) SCADA Systems

The SIP adjusts funding for System Control and Data Acquisition ("SCADA") Systems by $500,000, from $1.5 million to $1 million, for 2008. Looking at the Company's projected expenditures for 2008 through 2010, Staff is skeptical of the Company's higher dollar amount projected for the first year of the program. Accordingly, Staff proposed to levelize the cost of this program by averaging the projected expenditures for 2008 through 2010. (4035-4036; Exh. 272, p. 4).

The SCADA system program collects and permits control of the various distribution equipment and is the source of the information is collected and analyzed by sophisticated computer algorithms. (1964). System automation and technology enhancements and associated software and equipment upgrades are needed for these systems. The SCADA Systems program will begin the phase-in of the 4kV SCADA systems to take advantage of the complete

capabilities of the KYLE switches in the Company's 4kV overhead distribution system. The 4kV supply system has been in existence since the early 1930's. As of year 2000, the Company began a program to upgrade the 4kV grid system. Remote monitoring and control of the 4 kV system has been completed at the substation level with the completion of the USA SCADA system which provides important information on substation and feeder loads as well as several control functions from the Distribution Control Centers. (1965). The USA system will now be deployed at the feeder level, specifically at sectionalizing points at the critical location midway between two feeders outfitted with KYLE solid state controlled switches. The SCADA system will utilize the remote communications and control capability of these switches. (1964-1966). Staff's proposed $500,000 reduction is arbitrary and will impair the Company's ability to optimize the technical features of its KYLE switches. (1966).

(vi) <u>Process Improvement</u>

In the "Process Improvement" category, the SIP proposes no adjustments to five Electric Operations programs and projects identified in the Company's Exhibit 133, p. 2.[27]

(vii) <u>Security</u>

The SIP examined the Substation Operations' budget history for security expenditures. Finding no expenditures and minimal or zero budgets from 2004 to 2006, the SIP adjusted the 2008 and 2009 Substation Operations' funding for security from $4.1 million to $2 million each year. SIP also recommends that any of the $2 million that is not spent be returned to customers. (4026-4027; Exh. 274, p. 3).

Prior to 2008, Substation Operations' security initiatives and expenditures were funded under a separate corporate budget line associated with the World Trade Center attack. The

[27] The Company did not present Process Improvement programs or projects for Substation Operations or S&TO.

reason the historical expenditure level for security initiatives at the Substation Operations departmental level appears to be minimal prior to 2008 is that these expenditures were not in rates pending the outcome of federal and/or insurance reimbursement. (1969). In June 2007, the Company received federal reimbursements. (1968). Starting with 2008, the funding responsibility will be reassigned to the individual departments. (1967-1968).

Since the inception of the Security Enhancements program, expenditures have increased each year as the program transitions to maturity with program scope refinement and the incorporation of lessons learned. The actual historical expenditures associated with substations security projects have increased annually from 2004 to September 2007 ($500,000, $1.2 million, $2.9 million, and $3.0 million, respectively) and are in line with Substation Operations' 2008 and 2009 funding levels of $4.1 million. (1968-1969).

Exhibit 140, Con Edison's response to Staff's interrogatory 424, provides a detailed project schedule that outlines the Company's program to enhance physical security and to bring all substation facilities into compliance with the Company's Security specification by 2010. Substation Operations plans to install physical security systems consisting of closed circuit TV, monitoring, and access systems at six substations in 2008 and seven substations in 2009. The Company will also purchase "man down" radios for the substations in 2008 and 2009.

The funding is necessary to meet this schedule, and a reduction of funding will delay completion of important security enhancements that the SIP agrees are "of utmost importance." (4026). Staff's adjustment should be denied.

(viii) <u>Staff's Global Adjustment of S&TO Capital Programs</u>

Without any explanation, the SIP abandoned its project-specific review and examination of programs and projects for System and Transmission Operations' capital expenditure programs

for the transmission system and for system operations. Unlike their use of program and project analysis to develop a recommendation for the substation and distribution system capital expenditures, the SIP based their recommendation for transmission system and system operations capital expenditures solely on their view that the Company has historically over-budgeted for such expenditures.[28] (4005-4007). Based on the ratio of the Company's actual spending versus budget for the years 2004 through 2006, the SIP proposed to provide the Company only 58.4 percent of its projected rate year expenditures for S&TO capital programs. This works out to a $108.95 million adjustment to the Company's rate year expenditures.[29] (4005-4007; Exh. 274, pp. 2, 5).

The S&TO funding request for transmission operations is based on the most current information available. (Exh. 132). This request is designed to ensure the reliability of the transmission system, which is the backbone for supplying the customer load in the Company's service territory. The capital expenditures shown in Exhibit 132 are required in the Rate Year to ensure that the transmission system has the needed capacity to address increasing customer load and generating unit retirement, to replace and/or refurbish the aging transmission infrastructure and associated equipment, to improve safety and environmental performance, to allow implementation of mitigation strategies to reduce system risk, and to leverage new technologies to provide operational improvement. (1920-1921).

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[28] The SIP stated that the Company's "budget forecasts and actual expenditures for other major budget categories are more closely aligned" (4006), and made no global adjustment to the other major budget categories – Substation Operations (substations) and Electric Operations (distribution system).

[29] The SIP's testimony erroneously states that its adjustment is to the Company's "Transmission and Switching Station budget category." (4005) In actuality, as indicated in Exh. 274, pp. 2 and 5, the SIP's adjustment is to the "Transmission and Systems Operations Capital Budgets" for 2008 and 2009. The Company's initial and updated filings presented separate budgets for System and Transmission Operations, "Transmissions Operations Capital Projects" and for "System Operation Capital Projects" (respectively, Exhs. 123, 128, Exhs. 132 and 136). The Transmission and Systems Operations Capital Budgets referred to in Exh. 274, pp. 2 and 5, are the combination of these two separate capital budgets. Thus, the SIP's reference to an adjustment to the "switching station budget category" is misplaced. The Company's switching stations are a component of substations, and the Company's capital expenditures for switching stations are addressed in the Substation Operations budget. (Exhs. 121 and 130).

Staff's historically-based spending-ratio approach is particularly inappropriate for transmission budgets that involve large projects, predominately with service dates determined by system need. (1920). The Company's transmission operations budget includes major transmission reinforcement projects, such as the installation of the M29 line and relieving the East River load pocket, of a scope that the Company has not had to build for decades. Staff's approach would preclude recovery in rates for these needed projects. (2111-2112).

At times subsequent to developing budgets, factors that are largely out of the Company's control occur that can cause specific projects to be deferred and, thereby, decrease the spending scheduled for that year. Two such projects are the M29 project and replacing the 69kV feeders on the Queensboro Bridge ("QBB"). These are very large projects that by themselves represent a large portion of the S&TO budget. Due to the requirements associated with the Article VII approval process, construction of the M29 project, a $300 million project, was not commenced as originally scheduled and budgeted and is now moving towards commencing construction. (1921; 2109-2110). The QBB project has been deferred due to a two-year bridge-upgrade project of the City of New York. (1921; 2114).

Staff's methodology using historical performance to determine future spending appears to penalize the Company for deferring or delaying projects that are not within its control. Since the Company received the Article VII approval for M29 in August 2007, the absence of which caused the past slippage in the project, the Company appropriately anticipates spending in 2008 the $143 million projected in its updated filing for the M29 project. This single project represents 93 percent of the funding for S&TO capital projects that Staff is recommending for 2008. Because the M29 project has to be on line by 2010, construction must begin in 2008. (2115). Staff's recommendation will essentially stop other transmission work. (1922).

Staff's proposed 40 percent reduction would effectively limit all transmission system investment to only work associated with M29 and completion of in-progress work. It would prohibit the necessary investment in all other projects needed to support a reliable transmission system and infrastructure. (1923). Company Witness Longhi explained that the $143 million projected to be spent on the M29 project in 2008, plus the completion of the remaining work in progress, including the completion of the new Energy Management System, brings projected 2008 expenditures to about $160 million. Staff's forecasted 2008 budget of only $158.3 million (Exh. 274, p. 5) leaves no additional capital funding in 2008 for the $35 million needed to start the East 13th load pocket relief project, the $30 million needed for the phase angle regulator project for the West 49th switching substation, and the $5 million needed to begin the multi-year project to replace feeders 18001 and 18002. The East 13th Street project is required to meet design criteria to relieve a projected overload by 2010. (2115). The West 49th Street project is needed to meet design criteria and support load growth. These are not discretionary projects. Seven transmission feeder replacement projects per year are needed just to maintain the current 41-year average age of the pipe-type transmission system and avoid the major problems that derive from age-related deterioration. (1781-1783; 2124). Staff's adjustment would also not allow the Company to begin the replacement work for even the two feeders planned in 2008 for this reliability project. (2143-2145). Further, Staff's adjustment effectively eliminates a variety of other reliability projects that the Company plans to implement in 2008. (Exh. 132).

To develop its recommendation for S&TO's capital funding for the Rate Year, Staff developed a proficiency spending ratio that used actual spending versus budget for the years 2004 through 2006. The inclusion of the M29 and the QBB projects in Staff's calculations for the years 2005 and 2006 distorted the proficiency spending ratio because these large projects had

little or no spending during those years due to uncontrollable circumstances. If these two projects were excluded from the Staff's calculations, Exhibit 274, p. 5 would show that the Company is becoming increasingly proficient in forecasting S&TO projects. In fact, the proficiency spending ratio after excluding these two projects increases from 65 percent in 2004 to 73 percent in 2005 to 96 percent in 2006.

The SIP effectively eliminates most of the S&TO reliability projects without any assessment of the merits and need for any project. (2108-2109; 2112-2113). Staff makes its 40 percent reduction recommendation on an across-the-board basis without identifying any specific projects to be deferred or cancelled. Rather than simply assuming that past uncontrollable events will recur, all transmission and system operations projects should be analyzed based on the justifications and detailed project cost forecasts submitted by the Company. (1923).

Significantly, the SIP has criticized other parties for taking a similar "across-the-board," rather than project-specific analytical, approach to assessing the Company's capital programs. Thus, in assessing the recommendation of NYC witness Arnett calling for a cap on rates and/or capital expenditures, the SIP stated, "Our direct testimony provided recommendations for appropriate funding based on our review of Con Edison's specific infrastructure proposals." (4063).

In disagreeing with CPB witness Elfner's proposal for a 20 percent overall reduction in the Company's infrastructure budget, the SIP stated:

> [W]e do not believe that the appropriate remedy is an across-the-board generic reduction of 20%. Further specific analysis of the need and spending history of the projects for which Con Edison proposes to spend the requested funds is required, which Mr. Elfner does not provide. (4064).

Similarly, in disapproving Westchester's proposal for significantly reducing the Company's capital expenditures, the SIP states:

> [W]e do not agree with the blanket statements calling for reductions without a substantive analysis being provided. … [S]imply examining the Company's overall Capital spending data from recent years and comparing it with the overall expected load growth does not provide an adequate review of the specific infrastructure issues facing the Company. Without analyzing the underlying causes for the increased budget, including major project and program changes, Westchester's proposal is not reasonable in that it does not ensure customers will be provided with both safe and reliable service. (4066-4067).

Lastly, in rebutting the proposal of NYPA's Panel to cut the Company's construction spending by one third, the SIP states:

> [W]e see no evidence that NYPA's review of the Company's proposal incorporated an analysis of each specific program and project identified by Con Edison. … [W]e do not agree with the overall statements being made without NYPA providing further analysis of the underlying causes for the Company's increased budget, including an evaluation of major projects and program changes. To compare Con Edison in these areas with other utilities by way of a high level overview analysis is not be appropriate because such comparisons do not capture the unique situation or circumstance of a particular utility. This approach is not an adequate substitute for a thorough review of the Company's specific needs. (4068-4069).

Staff's proposed reduction to the Company's S&TO capital expenditures is made without a project-specific analysis. Staff's across-the board reduction for transmission and system operations projects would prohibit necessary investment in projects needed to support a reliable transmission system and infrastructure. Staff's adjustment should be rejected.

(ix) <u>Staff's Revised Reporting Requirements</u>

Pointing to the impact of the Company's proposed T&D capital expenditures on rates, Staff recommends that Con Edison be required to file with Staff a quarterly report that compares, by project, actual and projected schedules, as well as actual expenditures and rate allowances. The Company would also be required to provide justifications for any variance, by project as well as in the aggregate (3994). In its rebuttal testimony, the Company's Infrastructure Investment Panel identified several flaws in Staff's proposed reporting requirement.

First, requiring the Company to file status reports on a quarterly basis, rather than on an annual basis as is required under the 2005 Rate Plan, would be unduly burdensome and provide little if any additional benefits. (1989).[30] Indeed, the timing lag between accounts receivable and accounts payable and the inherent lag in accounting for all field operations would render such quarterly reports inaccurate and not useful. Second, requiring the Company to justify any variance in the projected schedule or expenditures for any project, as well as for all projects in the aggregate, rather than only a significant change (*e.g.*, 15 percent) in any project as is required under the 2005 Rate Plan, would be unreasonable and impractical. It would, for example, needlessly and arbitrarily require justification for even a $5,000 variation on a $1 million project and exceedance of the rate allowance by even a few thousand dollars in any quarter. (i*d.*). As the Commission is aware, departures from estimates, especially small ones, routinely occur for a wide variety of reasons, including weather and system contingencies and restated priorities.

Even if the Company were able to track on a quarterly basis all changes in project schedules and expenditures, regardless of the magnitude of such changes, and determine and verify the causes of such changes, such an undertaking would require additional manpower and system resources that could not possibly be cost-justified by the value that such insignificant and inconsequential information would provide to Staff. (1989-1990).

Finally, Staff's reference to project-specific rate allowances is puzzling; the Company is unaware of any breakdown of the Rate Year rate allowance that would identify the rate allowance for every project included in the T&D capital program. (1990). While there are

[30] While annual reports may be of little use in enabling Staff to monitor the Company's expenditures in the context of a one-year rate determination, quarterly reports, or preferably a single mid-year report, would only be of some use in facilitating Staff's oversight of the Company's expenditures under a symmetrical reconciliation mechanism that would allow the Company to exceed the rate allowance.

specific dollar amounts estimated for major projects, small projects are often not separately estimated.

The Company, of course, expects to continue its current frequent meetings with Staff. The Company will also continues to provide Staff with any information it requests, including information beyond that required by scheduled filings. Staff's proposed formal quarterly reports, however, especially quarterly reports required to capture and explain insignificant variations in estimates, would be unduly burdensome and of little value, and is unjustified.[31]

2. Production

a) The Company's Presentation

Con Edison's Electric Production Panel ("EPP") presented Con Edison's capital expenditure requirements for the years 2008 through 2010. (911-920; Exh. 54). Con Edison's Electric Production Construction Program provides the expenditure requirements for maintaining the infrastructure and systems of the Company's electric generating stations, *i.e.*, East River Station Units 6 and 7 and six Gas Turbines installed at various steam generating stations. The program establishes capital expenditures for functional programs relating to: 1) Environment, Health and Safety ("EH&S"), 2) boilers, 3) steam turbines, 4) mechanical equipment replacement, 5) electrical equipment, 6) control systems, 7) structures, 8) waterfront, 9) roofs and 10) security. It is designed to continue the safe, efficient, and reliable operation of the Company's in-City electric generation units. Past experience has shown that improvements and capital expenditures in each of these functional areas are required for continuous safe, reliable, and efficient plant operations. The selected functional programs address areas of the station that

[31] The Company similarly opposes Staff's recommendation the Company submit quarterly report on its secondary monitoring activities. (4037-4039). Quarterly reports are overly burdensome and provide little update between reports. Moreover, in its Order Implementing Outage Recommendations in Case 06-E-0894, (July 20, 2007), Directive No. 17, the Commission required that such reports be submitted on a semi-annual basis.

require improvement. For 2008 and 2009, the projected capital expenditures for these functional areas total $36 million and $39.7 million, respectively. (909-920; Exh. 54).

(i) Environment, Health and Safety

EH&S projects address conditions identifies during plant operations that could pose an EH&S risk, such as asbestos abatement, or address regulatory requirements such as fish life preservation. Projected expenditures in 2008 and 2009 are $2.6 million and $3.6 million, respectively. (911-913; Exh. 54).

(ii) Boilers and Steam Turbines

These project refurbish boilers and turbines in order to maintain rated electrical output and equipment reliability. Projected expenditures in 2008 and 2009 are $1 million and $3.25 million, respectively. (913; Exh. 54).

(iii) Mechanical Equipment Replacement, Electrical Equipment, and Control Systems

These programs include projects to replace and improve equipment and systems in three major functional areas of the station. These equipment replacements and improvements are required to address age-induced degradation, obsolescence, malfunction, and failures that might otherwise contribute to plant unavailability and unreliable operations. These programs include projects to upgrade equipment and systems by application of new technologies that expand the capability and efficiency of plant systems, improve response time, and significantly enhance the reliability of the electric supply. (914).

The Mechanical Equipment program includes the replacement and improvement of mechanical equipment, such as pumps, valves, heat exchangers, air compressors, tanks, fire protection, heating, and air conditioning. Projected expenditures in 2008 and 2009 are $5 million and $9.1 million, respectively. (915; Exh. 54).

The Electrical Equipment includes the replacement and upgrade of electrical equipment such as switchgear, transformers, batteries, uninterruptible power supplies, inverters, breakers, motors, cables, and backup generators. Projected expenditures in 2008 and 2009 are $5 million and $7 million, respectively. (915-916; Exh. 54).

The Control System program includes the replacement and upgrade of control systems throughout the station, *e.g.*, transmitters, distributed control systems, control panels and terminals, monitoring instrumentation, and wiring. Controls and instrumentation are replaced with currently available equipment that is often very different than existing hardware and consequently require significant upgrades to control rooms, conduits and cables, and power systems. The control system upgrades provide new capabilities, such as automatic operation of critical components, monitoring of many more parameters to aid plant operators, and faster response times, all of which significantly improve the operation of the station, especially during critical periods. Projected expenditures in 2008 and 2009 are $12 million and $2.2 million, respectively. (916-917; Exh. 54).

(iv) <u>Roofs, Structural, and Waterfront</u>

The East River facility was originally constructed in 1926. Its structures have been experiencing degradation due to normal wear and tear, age, and weather that, if left unaddressed, could create unsafe conditions to plant staff, and result in restricted access to plant areas as well as potential damage to plant equipment and structural integrity. (917-918).

The Structural program provides projects for general improvements to the station structures, such as steel and concrete, facades, foundations, walls, floors, stacks, driveways, bridges, and tunnels. Projected expenditures in 2008 and 2009 are $6.25 million and $11.5 million, respectively. (918-919; Exh. 54).

The Waterfront program addresses improvements to piers, docks, and related facilities and systems. Projected expenditures in 2008 and 2009 are $2 million and $1 million, respectively. (919; Exh. 54).

The Roofs program includes projects to replace and refurbish roofs and roof drains. Projected expenditures in 2008 and 2009 are $0 (significant work was completed in 2007) and $2 million, respectively. (919; Exh. 54).

(v) Security

The East River Generating Station and Substation Complex consists of the generating station, a multi-million gallon oil tank farm, and two substations, making it a vital facility for both Con Edison and the New York City metropolitan area. The security program for this facility includes projects to upgrade and integrate the security systems, restrict access and provide effective surveillance of the overall East River complex. The surveillance system will consist of new cameras, video monitors, card readers for access control, turnstiles, vehicle barrier surveillance, and door status monitoring in and around the facility. Projected expenditures to complete this work in 2008 are $1.6 million. (919-920; Exh. 54).

b) Other Parties' Presentation

No party to this proceeding proposed reductions to the Electric Production Construction Program.

3. Proposed Global Adjustments To Capital Expenditures

Several parties recommend arbitrary global adjustments to the Company's proposed T&D capital expenditures. CPB recommends that the Company's capital expenditures be reduced by approximately 20 percent. (4687). NYC would impose an unspecified rate cap, with an underlying "capital and O&M" cap, that would compel the Company to reduce its capital (and

O&M) programs. (4504). Westchester proposes that the capital program be cut by $600 million. (5462). The common flaw in all of these proposals is that they are unsupported by any, much less substantive, analyses or assessments of their potential impact on any or all of the projects and programs that the Company has proposed (1971-1972), and whether the Company could continue to provide safe and reliable service despite the recommended reductions in expenditure levels. As Staff so aptly put it with respect to Westchester's capital program reduction proposal:

> Without analyzing the underlying causes for the increased budget, including major project and program changes, Westchester's proposal is not reasonable in that it does not ensure customers will be provided with both safe and reliable service. (4066-4067).

Unlike Staff, which undertook a comprehensive evaluation of each of the Company's proposed projects and programs -- based on the Company's rate case presentation, the underlying workpapers and the Company's responses to hundreds of interrogatories relating to its proposed infrastructure investments (4065) -- CPB, NYC, and Westchester readily admitted that they did not analyze any of the Company's proposed infrastructure projects and programs. (4500; 4683; 5461). Instead, each would simply have the Company prioritize its planned capital projects and programs and undertake only those that can be funded within their respective arbitrarily-set budgets. (4498-4500; 4687; 4728; 5446).

While acknowledging that there is a need for additional infrastructure investments, CPB speculates that not all projects proposed by the Company may be necessary at this time. (4687). The only basis the CPB could muster for its speculation is the notion that any new project proposed by the Company that is necessary for safe and reliable service should have already been undertaken in the past. (4686). On cross-examination, however, CPB witness Elfner conceded that new projects that are needed to address future load growth should generally not be undertaken before they are actually needed for load relief. (4724). Thus, CPB refuted its own

assumption that any project not previously undertaken by the Company is not required for providing safe and reliable service. The CPB has advanced a standard for capital expenditures that is internally inconsistent, illogical, and untenable.

CPB was also unsure as to how its proposed 20 percent capital expenditure reduction would be effectuated. During cross-examination, when confronted with the possibility that the Company may not have sufficient funds to undertake reliability-related projects, or to achieve the targets proposed under Staff's reliability performance mechanisms, CPB witness Elfner revised his proposal to require a 20 percent reduction in capital expenditures only after setting aside sufficient funds for all reliability-related work, as well as for vaguely-described "commission-directed priorities." (4729-4730). A short time later, however, CPB's witness reverted to his original proposal to require a 20 percent reduction to the Company's full capital program, for a reduction of $372 million. (4732).

Unlike CPB and Westchester, NYC provided no recommendation as to the amount by which the Company's capital expenditures would be reduced. NYC's proposal also differs from those of CPB and Westchester in that it calls for close regulatory oversight. Specifically, NYC witness Arnett would have the Commission determine the level of the cap to be placed on the Company's rates and/or expenditures (4500), and would leave it to the Company to determine which of its capital projects should be allowed to proceed (4498), subject to Staff's oversight. (4540). In addition, the Company would be required to report to the Commission the extent to which individual projects would have to be deferred, curtailed, or delayed. (4498-4499). The Company would also be permitted to petition the Commission for deferred recovery if the Company determines that a project that cannot be funded within the cap is required to ensure safe and reliable service. (4499). Although Mr. Arnett recommended that the cap be set "at the

point at which the cost of providing a service is greater than the incremental benefit of receiving it" (4503), he declined to propose a method for establishing that point. (4540). Mr. Arnett did, however, agree that capping the Company's expenditures would justify reconsideration of the reliability performance targets. (4544).

Westchester, on the other hand, would not excuse the Company from meeting any performance target, even if the Company was denied sufficient funds to meet the target. According to Westchester witness Radigan, the Company "would have to make the decision [as to] what is the best thing for Con Edison to do and there might be a small penalty associated if they don't do that." (5506). In effect, Westchester would put the Company's infrastructure on a 'starvation diet' and see whether the delivery system can survive. Westchester points to the moderate rate increases provided under the 2005 Rate Plan as evidence that the delivery system can flourish even on a 'starvation diet'. However, as explained in greater detail elsewhere in this Brief, Westchester is fooling no one but itself. Notwithstanding the moderate rate increases, the 2005 Rate Plan did not deny the Company any capital funds. The Company was permitted, subject to regulatory oversight, to incur expenditures in excess of the costs reflected in rates without limitation, when it deemed such expenditures necessary to provide safe and reliable service, with recovery of those excess costs deferred for recovery in this proceeding. Westchester's proposal in this proceeding to drastically limit the Company's ability to fund infrastructure projects would have catastrophic results.

It should be clear that adoption of any of the blanket reductions to the Company's T&D capital program proposed by CPB, NYC or Westchester would put the Company in the untenable position of foregoing or delaying projects and programs that, in the view of both the Company and Staff, are necessary for the provision of safe and reliable service. Continued plant investment

is needed in order to maintain an electric system strong enough to support the New York City and Westchester County regions with the high levels of service reliability required for the area's future economic prosperity. The Company understands that these parties' proposals are put forward in a good faith effort to moderate the Company's expenditures levels. However, the proposals are strictly results-oriented and, in the end, not in the best interests of the consumers and should be rejected.

4. Customer Operations

a. Advanced Metering Infrastructure

The Company proposes to implement three pre-deployment advanced metering infrastructure ("AMI") demonstration projects during the rate year and thereafter deploy AMI throughout its service territory. (766-770). This proposal is consistent with the Company's March 28, 2007 AMI filing in Case Nos. 94-E-0952, 00-E-0165, and 02-M-0514, the Commission's AMI Proceeding.[32] (3944-3945). The demonstration projects would involve approximately 300,000 electric and gas meters in Westchester County installed or retrofitted by the end of 2007 under the Company's Automated Meter Reading ("AMR") program and upgraded as part of the AMI project as well as 100,000 electric and gas meters to be installed in each of Queens and the Bronx/Upper Manhattan during 2008. (769-770). The rate year work would also include the installation of data collection and communications equipment and completion of the installation of a Meter Data Management System ("MDMS") to allow for integration of data provided by the meters with the Company's existing computer applications.[33]

[32] Case No. 94-E-0952, In the Matter of Competitive Opportunities Regarding Electric Service, Case No. 00-E-0165, In the Matter of Competitive Metering, and Case No. 02-M-0514, Proceeding on Motion of the Commission to Investigate Competitive Metering for Gas Service (collectively, the "AMI Proceeding").

[33] The MDMS is also necessary to support customer billing under the Company's proposed Mandatory Hourly Pricing ("MHP") program expansion. (776; 891). The communications infrastructure installed for AMI will also be used for MHP. (887-888).

(769) The pre-deployment demonstrations will permit the Company to evaluate selected communications technologies and AMI functionality. (770; 769). Once the demonstration projects have achieved their objectives, the Company would begin to install AMI throughout its service territory at the rate of approximately 800,000 meters per year with an expected completion date of 2014 for all 4.4 million meters. (768).

The Company expects that AMI will eliminate the need for a meter reader to view or drive by every meter and enable more frequent meter reading, thus providing billing data for time-differentiated rates and support for demand-side management programs. (767; 768). AMI is also expected to provide enhanced distribution system information relating to power outages and service restoration, power quality, and instances of meter tampering. (768). The Company also expects that AMI will facilitate the Company's expansion of its MHP program to a much larger group of customers. (890-891).

In general support of the Company's proposal, City witness Chernick testified that AMI is consistent with Mayor Bloomberg's PlaNYC, which supports the universal installation of advanced meters by 2014. (4976). The CPB, through its witness Elfner, also testified that AMI is expected to enable environmental benefits and reduce costs for customers: in particular, it will reduce meter reading costs, increase meter accuracy, reduce the number of estimated bills and associated customer billing inquiries, provide customers with more information about their service usage and facilitate their participation in demand-side management programs, and enhance the Company's ability to identify the extent of an outage and more effectively restore service. (4684).

Staff raises objections to consideration of the Company's AMI proposal in the context of this rate case. CPB and the City propose changes in the program relating to the timing of implementation and cost recovery. (3273-3275; 4989).

Staff and CPB oppose the Company's AMI proposal on the grounds that the authorization and implementation of the AMI proposal should await the Commission's decision in its ongoing AMI Proceeding. (3945; 4687). Staff also opposes the Company's AMI proposal on the ground that it will affect both electric and gas operations. Therefore, in Staff's view, decisions regarding the Company's AMI plan should not be made in a proceeding addressing only electric service. (3945-3946).

Despite CPB's position (through Dr. Elfner) that the Company's AMI proposal should be deferred for consideration in the PSC's generic proceeding, CPB witnesses Elfner and Schultz distinguish the Company's proposal to conduct "AMI-related pilot programs" for which CPB agrees funding should be approved. (4687; 3273). CPB asserts that the Company's AMI costs should not be embedded in the Company's revenue requirement, however, as they are "one-time in nature." (3273). CPB (through Mr. Schultz) also questions why the Company proposes to install the AMI communication system in advance of meter installations and how the system can be tested before the meters are installed. (3273-3274). Finally, the City proposes that meters should be deployed to the Company's largest customers first. (4976).

For the reasons hereinafter given, these objections do not provide a basis for the Commission to reject the Company's AMI proposal in this proceeding.

b) <u>The Company Should Be Allowed To Implement Its AMI Proposal in the Rate Year</u>

That a generic proceeding on AMI is pending does not foreclose the Commission's consideration of the Company's AMI proposal and the Company's implementation of that

proposal during the rate year. Staff's objection to consideration of the Company's AMI pre-deployment project proposal was premised on the possibility that the Commission would have earlier addressed the issues raised here in the AMI Proceeding, in which Staff expected an order before resolution of this case. (3944-3945).

Recent developments cast serious doubt on the likelihood that the Commission will issue a decision in the AMI Proceeding before the Commission's order is issued in this proceeding. On October 10, 2007, the Commission issued a Notice Seeking Comment ("AMI Notice") in the AMI Proceeding. Specifically, the Commission seeks comment in the AMI Notice on the features and functions, proposed by Staff, for inclusion in a standard for AMI systems and also invites parties to address any other matters related to an AMI standard. Comments are due by December 10, 2007. With over 30 parties on the current service list, it seems likely that extensive and contradictory comments will be submitted. It does not appear that this proceeding will be concluded anytime soon. Equally important, Staff witness Rieder admitted as much on cross-examination when he acknowledged that he could not predict when the Commission would issue its decision in the AMI Proceeding. (3953). In light of the probability that the AMI Proceeding will not be concluded before rates go into effect in this case, April 1, 2008, the Commission should authorize the Company in this proceeding to implement its AMI proposal.[34]

c) <u>Delaying approval of AMI will prevent the achievement of public policy goals and utility system enhancements</u>

The Company's AMI proposal is premised, in substantial part, on the contribution full deployment of advanced metering is expected to make in the achievement of pressing public policy goals related to energy requirements and usage. By rejecting the Company's proposal in

[34] In the unlikely event that the Commission issues its decision in the AMI Proceeding before rendering its decision in this proceeding, the Commission certainly could take due note of its AMI decision in issuing its decision in this proceeding and should provide for recovery in rates of the costs the Company would incur in complying with the AMI decision.

this rate case in favor of consideration at a later date, Staff is taking a chance that delaying the Company's demonstration projects in anticipation of the Commission's consideration of the generic issues associated with AMI will not impede the achievement of those pressing goals.

Staff witness Rieder claimed that because the Commission is evaluating AMI on a generic basis, the Company's plan should be considered "in the context of the overall benefits and costs the Commission is considering with regard to AMI." (3945). Furthermore, he asserted, "it would be inappropriate to make decisions about moving forward with AMI [affecting both electric and gas metering] in a proceeding that only considers electric matters." (3945-3946). Based on this testimony, he proposed to remove AMI-related costs, which he estimates at $25 million, from the rate year revenue requirement. (3946; see also Exh. 241 and Exh. 269, p. 9). These non-substantive excuses for failing to support AMI fly in the face of pressing energy issues in New York.

The Company testified that AMI "will provide a basis for cost-saving changes in customer operations as well as enabling benefits for customers, the environment, and society generally." (767-768). In particular, the Company expects societal benefits to be realized from AMI when customers have access to the information necessary to understand and better control their energy usage. (767).

> AMI enabled meters can readily support customer participation in demand response and demand-side management programs. AMI can also support time-based tariff programs, such as critical peak pricing, and facilitate customer price response. (i*d.*)

This view is shared by City Witness Chernick, who testified to the City's support for the universal installation of advanced meters by 2014 because advanced metering is essential to customers' participation in demand response programs. (4976). Mr. Chernick further testified that the Company's proposal is consistent with PlaNYC, a program proposed by City of New

York Mayor Bloomberg to reduce energy consumption. *(id.)* He notes that "increased use of advance metering technology can provide numerous economic and environmental benefits to customers" (4987) and quotes from the Commission's order initiating the AMI proceeding:[35]

> An advanced metering infrastructure [footnote omitted] and use of new intelligent technology provide the foundation for electric utilities and consumers to make informed choices about energy suppliers and usage on the basis of price and time-of-use of energy. Use of advanced electric metering systems enables electric utilities and consumers to manage the need for additional supplies to satisfy growing demand, to avoid use of high priced fuels, and to moderate pricing volatility associated with use of expensive generation in times of peak demand.

(*id.*)

AMI is also expected to provide Con Edison with benefits derived from the availability of enhanced distribution system information relating to power outages, power restoration, and power quality. (768). This information is expected to aid Con Edison in understanding the scope of outages and working through service restoration more efficiently, matters of great public concern following the 2006 outages in Long Island City and Westchester.[36] The availability of data from meters that are otherwise difficult for Company personnel to have access to is expected to aid the Company in identifying meter tampering. (*id.)*

The Company proposed AMI demonstration projects to validate performance and assumptions made in its business model, determine if its goals for AMI are realistic and achievable using currently available commercial technology and communications systems, and develop interfaces needed to integrate data from an AMI system with its legacy systems.

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[35] Case No. 94-E-0952 et al., Order Relating to Electric and Gas Metering Services (August 1, 2006), pp. 1-2.
[36] Case No. 06-E-0894, Proceeding on Motion of the Commission to Investigate the Electric Power Outage of Consolidated Edison Company of New York, Inc.'s Long Island City Electric Network; Case No. 06-E-1158, In the Matter of Staff's Investigation of Consolidated Edison Company of New York, Inc.'s Performance During and Following the July and September Electric Utility Outages; Case No. 06-M-1108, Petition of Certain Members of the New York State Legislature Regarding Consolidated Edison of New York, Inc.'s Electric Service Outages, Order Implementing Outage Recommendations (July 20, 2007).

Delaying these projects puts off to an uncertain future date the initiation of these demonstrations and, therefore, the near-term possibility of AMI's contributing to the achievement of the important energy-related goals cited by the Commission in commencing the AMI proceeding.

a) <u>The pendency of the generic proceeding should not foreclose demonstration of AMI technologies</u>

Staff's rationale for referring consideration of the Company's AMI proposal to the generic proceeding might have made a modicum of sense when Staff anticipated that the Commission might rule in the generic case before it ruled on the Company's electric rate request. After Staff witness Rieder conceded his uncertainty about when the Commission might act in the generic proceeding (3953), Staff's opposition to consideration of the Company's demonstration proposal in this proceeding can only be viewed as an impediment to the development of AMI in Con Edison's service territory. The demonstration projects are needed to evaluate the communications technologies the Company expects to employ. (770). The prospect of the Commission not providing funding for AMI must necessarily cause the Company to reevaluate its current efforts and consider terminating or suspending those efforts. (818, 824) Thus, prompt approval of the Company's proposed demonstrations is an essential part of the Company's planning for AMI. (817-818; 820; 4989).

CPB claims that if the Commission were to authorize the Company to proceed with its AMI proposal in this proceeding, it would "prejudge the outcome of [the generic] review" of the utility filings in the AMI Proceeding as well as the evaluation of the pilot programs. (4685). However, CPB recognizes that the "pilot programs . . . are intended, among other things, to provide actual data on the reasonableness of the cost and performance assumptions underlying the Company's March 28, 2007 filing [in Case 04-E-0952]." (4685). Accordingly, CPB states

that the Company should be permitted to recover the costs of its AMI-related pilot programs, but not through rate base recovery. (*id.*)

CPB's rationale for denying rate base treatment appears to be its assumption that the "pilot program" installation will not have an on-going benefit. This is not correct. The meters installed for AMI will remain in place whether or not the Company's AMI plan is approved as proposed (820), and the investment in the MDMS and communications infrastructure for AMI will continue to provide for reduced meter reading costs and be useful for MHP. (776; 891; 887-888). Rate base recovery of these costs as well as the meter and meter installation costs should be allowed as proposed.

2. <u>Changes to the AMI deployment schedule will not achieve benefits earlier.</u>

The City proposed that AMI meters should be deployed to the largest customers first in order to achieve the greatest potential return in terms of demand reduction. (4976). This proposal ignores both that the chief expected source of savings from AMI is avoidance of meter reading expenses and that the Company was separately proposing to expand the group of customers subject to mandatory hourly pricing. (768; 771-779). Implementing the City's substitute deployment schedule would be counterproductive and should be rejected.

As noted by the Company, in order to reduce the Company's meter reading costs, meters must be deployed so as to cover complete meter reading routes, as opposed to the selective deployment recommended by the City. (822-823). In addition, the Company's proposal to expand its MHP program will facilitate the Company's largest customers' (*e.g.*, customers over 500 kW) participation in demand response programs. (772-776). Imposing a cost-effectiveness test on the use of AMI based on customer size is inappropriate when the cost of meter reading depends principally on geographic location, not customer size. (822). The City's proposal

would deny the Company the savings on meter reading that underlie its AMI business case. (822-823).

The Company agreed that multiple deployment strategies can be used for AMI implementation. (821). That is not to say that a different strategy will yield the same or greater benefits. The Company proposes to install the communications infrastructure prior to the installation of meters. *(id.)* Under this approach, meters can be communication-enabled as they are installed, thereby facilitating the widespread geographic deployment of AMI and achieving the expected meter reading savings. (821).

3. <u>The implementation of AMI will be "lumpy" so smoothing the recovery of AMI expenses is not reasonable.</u>

CPB challenged the installation of a communications system before meters are installed and the projected expenditure of most O&M funding in the rate year considering that meter installation is projected over three years. (3273-3274). In questioning this deployment strategy, CPB challenges the Company's ability to test the communications system before the meters are present. (3274). CPB misunderstands the Company's deployment schedule and how it affects projected O&M expenses.

CPB opposes the Company's recovery through the revenue requirement of any costs related to the Company's AMI proposal. (4685) However, it accedes to the recovery of costs for what it terms the "pilot" programs, which being "one-time in nature" should be recovered in some other manner. *(id.;* 3273). CPB claims that AMI costs should not be reflected in the rate year unless cost savings can also be included. (3275). CPB's misperception of the benefit of installing the communications system before the meters are in place contributes to its objection to the recovery of AMI costs through base rates for this reason. (3274). However, in its recommended adjustments, it proposes that if 30 percent of the capital expenses projected for a

three-year period beginning with the rate year are to be incurred in the rate year, only 30 percent of projected O&M costs should be recovered. *(id.)* This recommendation fails to recognize that the expected O&M costs are driven by the proposed deployment strategy of installing the communications system before other system investments are made, so that meters can be made operational as soon as they are installed. (821). Although this schedule does require that a substantial portion of projected O&M expenses will be incurred prior to full implementation of AMI (Id.), it has a rational basis for which no party has raised a reasonable objection.

4. There is no merit in Staff's objection to addressing AMI on the ground that the Company's AMI proposal relates to both electric and gas service

Staff's contention that a program having an impact on both electric and gas service should not be addressed in an electric case is a makeweight argument. (3945-3946). The Company notes that Staff's opposition is based in part on the Joint Proposal in the Company's most recent gas base rate proceeding.[37] (819). However, Staff only cites to the fact that the Joint Proposal in that case did not address the substance of the Company's AMI proposal and does not mention that the proposal approved by the Commission provides for the Company to defer its AMI expenditures.[38] Staff's argument also ignores the fact single service rate cases frequently address programs common to the various services of a combination utility and adjust rates for that service's allocated share of total costs, as was the case for AMI expenditures in the recent gas proceeding. (819).

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[37] Case No. 06-G-1332, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York for Gas Service, Order Adopting in Part the Terms and Conditions of the Parties' Joint Proposal (issued September 25, 2007) (*See* Joint Proposal, p. 15).

[38] *Id.* Implicit in the Commission's approval of expense deferral is a recognition that the deferred expenses will be recoverable in the future. The 2005 Rate Plan is another example of the Commission's willingness to consider a common program in a rate case affecting only one service. In the 2005 Rate Plan Order, the Commission approved the Company's proposal to install AMR on a saturated basis in Westchester and recover the capital costs of that project through the reconciliation of T&D expenditures provided for in that case.

Given the multiple benefits of the Company's AMI proposal and the projected delay in the resolution of the AMI Proceeding, the Commission should authorize the implementation of the Company's AMI proposal, including base rate cost recovery. Delay in the Commission's action on this proposal will cause the Company to reevaluate its current efforts and consider terminating or suspending those efforts, to the detriment of its customers and other stakeholders.

B. <u>Deferred T&D Costs</u>

Approximately $260 million of the $1.2 billion rate increase requested in this proceeding, or about 22 percent of the total revenue requirement, is related to T&D capital expenditures incurred by Con Edison during the period covered by the 2005 Rate Plan in excess of the capital expenditures reflected in rates. More specifically, the revenue requirement for the Rate Year includes (1) some $195 million in estimated carrying charges that will accrue during the Rate Year applicable to the total estimated T&D capital expenditures incurred during the three-year period covered by the 2005 Rate Plan in excess of the expenditures that were reflected in the rates (2457), plus (2) some $66 million in unrecovered carrying charges accrued during the third year of the 2005 Rate Plan (the twelve months ending March 31, 2008) on expenditures incurred during the three-year period covered by the 2005 Rate Plan in excess of the levels reflected in rates -- representing one third of the total $198.8 million in estimated unrecovered carrying charges accrued during the third rate year that the Company proposed to amortize over three years in this proceeding (2431, Exh. 95, Sch. 4).[39]

[39] In addition, the Company has recovered from accrued customer credits some $60 million in carrying costs accrued during the first year of the 2005 Rate Plan on T&D capital expenditures in excess of the levels reflected in rates (2519), plus some $138.7 million in carrying costs accrued during the second rate year of the 2005 Rate Plan on T&D capital expenditures incurred during the first and second years in excess of the levels reflected in rates (2520). The Company's recovery of these costs was effectuated through the netting provisions of the 2005 Rate Plan described in more detail below.

1. The 2005 Rate Plan

The 2005 Rate Plan established by the Commission in Case 04-E-0572, based on a Joint Proposal executed and supported by some 30 parties,[40] provided for a unique, although not unprecedented, reconciliation mechanism for T&D capital expenditures, which the Commission found was in the best interests of ratepayers.[41]

a) The Capital T&D Reconciliation Provision

The 2005 Rate Plan provides for the reconciliation of various items of expense, such as property taxes and environmental remediation; that is, some or all of the difference between forecast expenses for such items, as specified in Appendix F to the 2005 Rate Plan, and actual expenses are to be deferred for later recovery from or credit to customers.[42] In addition, the 2005 Rate Plan provides for the reconciliation of carrying charges on differences between targeted levels, specified in Appendix G to the 2005 Rate Plan, and actual carrying charges accrued on capital expenditures for T&D.[43]

The reconciliation provision applicable to T&D capital expenditures states as follows (2005 Rate Plan Order, App. I, pp. 11-12):

> If, at the end of any Rate Year, average net plant in the transmission and distribution ("T&D") category is either greater than or less than the amount set forth in Appendix G ("T&D Capital Target"), the revenue requirement impact of such variation, as calculated below, will be deferred and recovered from or credited to customers in the manner described above….The revenue requirement impact will be calculated by applying an annual carrying charge factor of 13.95 percent (representing a combination of pre-tax rate of return of 11.40 percent and depreciation of 2.55 percent) to the actual Rate Year variance from the T&D Capital Target.

[40] 2005 Rate Plan Order, p. 6 fn. 13.
[41] 2005 Rate Plan Order, pp. 38-39.
[42] 2005 Rate Plan Order, p. 34.
[43] A reconciliation for generation-related capital expenditures is also provided, for underspending only, and is not germane to the discussion here. See, 2005 Rate Plan Order, App. I, pp. 12-13.

In its order adopting the 2005 Rate Plan, the Commission found that the capital T&D reconciliation provision would protect both the Company and its customers against expenditure forecasting errors and would ensure that the Company is not precluded by a lack of funds from undertaking meritorious projects that were not covered by the level of forecasted expenditures reflected in rates. As stated by the Commission in summarizing Staff's support of the T&D reconciliation provision, customers benefit from construction investments necessary to provide safe and adequate service and the use of a reconciliation for T&D capital expenditures "eliminates any reason the Company may have not to make necessary infrastructure investment."[44] Accordingly, the Commission concluded that, although reconciliations are, for the most part, reserved for expense items that are outside of the Company's control, such as interference costs and property taxes, there was much justification in this case to include T&D capital expenditures in the reconciliation mechanism:

> The reconciliation of carrying charges on T&D investment is not routine, but such an approach was adopted in two recent cases …. The reconciliation of capital budget items in this case is proposed not because of any party's disagreement with the T&D capital projects the Company expects to undertake, or with its budgeted amounts per project, but because of DPS Staff's doubts that the Company can complete all of its T&D capital projects on the schedule originally proposed by Con Edison. Because of this practical concern, the annual T&D capital budget targets in the JP are about $200 million per year lower than what the Company continues to believe it will invest in the coming three rate years.[45]
>
> * * *
>
> The costs in these latter categories are primarily within the Company's control. However, given the extremely large capital investment planned over the coming three years and the previously discussed doubts about the Company's ability to proceed with all construction on the pace the latter originally envisioned, these reconciliation provisions are reasonable in the circumstances presented.

[44] 2005 Rate Plan Order, pp. 36-37.
[45] 2005 Rate Plan Order, p. 35.

> PULP's fundamental point here seems to be that terms that establish targets, and provide for reconciliation of forecast and actual costs, are necessarily only beneficial to the Company and only harmful to ratepayers. The basis for this implicit assumption is not explained by PULP. Moreover the assumption is not reasonable. Use of a forecast and providing for the reconciliation of the carrying charges on needed T&D investment, for example, helps ensure that ratepayers do not pay carrying charges on plant that is needed but that, for various practical reasons, may not be constructed in accordance with planning schedules.[46]
>
> * * *
>
> The proposed reconciliation of carrying charges in capital investments is not typical. Given the facts and circumstances here, pertaining to whether the Company can complete all of its planned capital projects, and the relatively large amount of revenue requirement at stake, these provisions reasonably reduce the risk of forecasting errors for ratepayers and shareholders alike.[47]

b) <u>The Provision for Regulatory Oversight</u>

The reconciliation mechanism in the 2005 Rate Plan was not only unique in that it provided for a true-up of capital expenditures that are, at least for the large part, within the Company's control, it was also unique in that it provided for on-going regulatory oversight of the Company's T&D construction activities and expenditures. Specifically, the 2005 Rate Plan required the Company to file with the Commission "comprehensive" status reports on its construction activities, including detailed reports on completed, ongoing, and new projects, to enable Staff -- and other interested parties -- to closely monitor the Company's capital T&D expenditures. Specifically, the capital T&D reconciliation provision requires that (2005 Rate Plan Order, App. I, pp. 11-12):

> The Company will, for informational purposes, file with the Secretary to the Commission and submit to the Signatory Parties in this proceeding, subject to confidentiality concerns, by May 1, 2005 and thereafter by January 31 each year, a comprehensive status report on its annual T&D expenditures. The report should, at a minimum:

[46] 2005 Rate Plan Order, pp. 38-39.
[47] 2005 Rate Plan Order, pp. 111-112.

a. identify all completed projects, the date they were completed, and the costs of the project;

b. for ongoing projects, provide their status, estimated dates of completion, and costs expended to date;

c. for projects where the Company's expenditures have varied by more than 15 percent from estimates previously provide to the parties, provide a detailed explanation and justification for such variation; and

d. for each new project (*i.e.*, those not previously identified by the Company in this proceeding), provide a detailed project description, justification of the need for the project, cash flow requirements from inception through completion, an explanation of how the cost figures were derived, and supporting work papers and other back-up materials.

The 2005 Rate Plan was clear, however, that the Company would, subject to Staff's oversight, undertake T&D investments based solely on system and reliability needs and would not be bound in any manner to the specific projects identified in the Company's April 2004 rate filing or in any of the status reports filed pursuant to the 2005 Rate Plan (2005 Rate Plan Order, App. I, p. 12):

> The Company has the flexibility over the Electric Rate Plan to modify the list, priority, nature, and scope of the capital projects identified in its April 30, 2004 filing or in any of the status reports filed pursuant to this section.

Nor would the Company be limited to the target expenditure levels used to set rates under the 2005 Rate Plan. Those target levels, which were about $200 million per year lower than what the Company had forecasted it would invest in T&D capital projects during the three-year rate plan, were derived based on historical expenditure levels, plus inflation, and were not connected with specific projects or plant additions, nor were they intended to limit or define in any way the Company's construction programs and expenditures.[48]

[48] 2005 Rate Plan Order, p. 35; Case No. 04-E-0572, Exh. 9, Response 61. Exhibit 9 in the record in Case No. 04-E-0572, which contains the signatory parties' responses to the Administrative Law Judge's questions about the Joint Proposal, was cited extensively in the 2005 Rate Plan Order (see, *e.g.*, p. 9 fn. 21; pp. 34-35, fns. 107-109) and the

c) The Netting Provision

In order "to minimize the amount of costs to be deferred" for collection in this proceeding, the 2005 Rate Plan includes another uncommon provision (2505), which allows Con Edison the opportunity to set off deferred costs against certain credits due ratepayers.[49] Specifically, the 2005 Rate Plan provides (2005 Rate Plan Order, App. I, p. 10):

> However, at the end of each Rate Year and subject to audit and prudence review, the Company may apply any available credits, except credits associated with TCC's, to offset the deferred balance.

The "subject to" language does not require Staff to undertake an audit or review of any specific expenditures, but "preserves Staff's right to audit or conduct a prudence review of credits or debits that have been netted."[50]

2. Recovery of the Deferred T&D Capital Costs

Staff, the only party to have conducted a detailed review of the Company's T&D capital expenditures since commencement of the 2005 Rate Plan, supports the full recovery by the Company of the carrying charges associated with those capital expenditures (4125-4129). Several other parties, although not challenging any specific capital T&D expenditures made by the Company, raise concerns as to the magnitude of the Company's T&D investments during the period covered by the 2005 Rate Plan. (4468, 4680). The only party to question recovery of the deferred T&D capital costs is CPB, which vaguely claims that further scrutiny of the Company's past T&D expenditures is appropriate before the Company is authorized to recover those costs.[51]

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information provided in the exhibit was relied upon by the Commission in its "conclusions concerning the JP's overall reasonableness." (2005 Rate Plan Order, p. 105).

[49] 2005 Rate Plan Order, pp. 34-35.

[50] Case No. 04-E.-0572, Exh. 19, Response 52.

[51] During its cross-examination, CPB stated, for the first time, that it had expected further scrutiny of the Company's past T&D expenditures before the Company was authorized to recover its deferred T&D capital costs. (4741, 4750). CPB, however, never specified the form or extent of such further scrutiny. In fact, while CPB calls for a "comprehensive independent audit of Con Edison, with a focus on the Company's capital investment in relation to the needs of its customers" (4682), CPB does not recommend that the results of that audit be applied to Con

As demonstrated below, there is no basis whatsoever to deny the Company full and timely recovery of carrying charges relating to the capital T&D expenditures incurred during the three-year period covered by the 2005 Rate Plan.[52]

To begin with, although some parties feign surprise at the magnitude of the T&D capital-related costs incurred by the Company during the term of the 2005 Rate Plan, such surprise is dubious for several reasons, especially when expressed by parties to this proceeding who were also active parties to the Company's last electric rate proceeding (Case No. 04-E-0572).[53]

First and foremost, every party to Case No. 04-E-0572 received the annual status reports that the Company was required to file under the 2005 Rate Plan, each of which showed the actual versus forecast capital expenditures in the prior year and the new forecast for the upcoming year. (Exhs. 141-143).[54] It is inexcusable for parties who were served with the Company's detailed status reports to have ignored those status reports and to have waited until the Company sought recovery in this proceeding for its prudently-incurred capital costs to raise for the first time their concerns with the level of the past capital expenditures. Second, all of the parties to Case No. 04-E-0572 were well aware, and the 2005 Rate Plan Order made it abundantly clear, that the annual T&D capital expenditures reflected in rates were about $200 million per year lower than what the Company claimed it would need to invest during the rate plan period.[55] In fact, based on that fact alone, the parties to Case No. 04-E-05472 estimated

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Edison's past expenditures, or even to expenditures incurred during the Rate Year, but only "as part of a review of rates for Con Edison's electric operations for the rate year beginning April 1, 2009." (4688).

[52] CPB and Westchester County would amortize recovery of the $198.8 million in estimated unrecovered carrying charges accrued during the third year of the 2005 Rate Plan over a period far longer than the three years proposed by the Company. (4693-4694, 5466). These longer amortization proposals are addressed elsewhere in this brief.

[53] See 2005 Rate Plan Order, pp. 3-4; App. II.

[54] Although the Joint Proposal contemplated that the annual status reports filed with the Commission would be served only on the Signatory Parties, the 2005 Rate Plan Order (p. 105) required that the reports be served on <u>all</u> interested parties.

[55] 2005 Rate Plan Order, p. 35.

that, by the end of the third rate year, the net deferred carrying charges for T&D projects could approximate $126 million.[56] Finally, the Company has been consistently exceeding the T&D capital expenditures reflected in rates at least since 2000. In fact, both Staff and NYC noted approvingly in their investigative reports on the July 2006 service interruption in the Long Island City network that, for the years 2000-2005, the Company spent approximately $1.2 billion, or about 43%, more than its $2.8 billion rate allowance for T&D capital projects, and exceeded its own capital budget in each of those years by 5-30%.[57]

Assuming the mantle of a captious critic, CPB takes Staff (and the Commission) to task for somehow falling short in its monitoring and oversight of the Company's capital expenditures. While readily acknowledging that it has not analyzed whether the capital expenditures incurred by the Company since 2005 were made in a cost-efficient manner (4720; Exh. 313), CPB claims, without any substantiation whatsoever, that the Commission's oversight has failed "to ensure that capital improvements are made in a cost effective manner" (4681), and that the 2005 Rate Plan permits the Company to recover capital expenditures that exceeds the level on which rates are based, "apparently without an examination to ensure that the investment is necessary and/or funds are spent in an efficient manner." (4680-4681). When confronted during cross examination with the 2005 Rate Plan's provisions for regulatory oversight of the Company's T&D capital expenditures, CPB admitted that it was familiar with and supported those provisions (4714),[58] that it received the Company's annual status reports (4715), that it did not object to their adequacy (4752) and that it did not even inquire of Staff whether Staff reviewed

[56] Case No. 04-E-0572, Exh. 9, Response 12.
[57] Case No. 06-E-0894, Department Of Public Service Staff Report On Its Investigation Of The July 2006 Equipment Failures And Power Outages In Con Edison's Long Island City Network In Queens County, New York (February 2007), pp. 135-136; Investigation By The City Of New York Into The Northwest Queens 2006 Power Outages (March 2, 2007), p. 112, Table 5-2.
[58] In its Statement in Support of the 2005 Rate Plan submitted to the Commission, CPB heralded the capital T&D reconciliation provision, including the provision for regulatory oversight, as a "pro-consumer provision." (4713).

the Company's submissions or followed up with the Company on any significant deviations in project schedules or costs. (4753-4754). The only support CPB could muster for its criticism of Staff's oversight of the Company's T&D capital expenditures is the absence of a full report by Staff on its review of those expenditures in this proceeding with recommendations for the disallowances of at least some of those past capital expenditures. (4755-4756; 4758).

CPB's criticism of the regulatory oversight of the Company's past capital T&D expenditures and the aspersions it casts on the efficiency and effectiveness of the Company's capital investments are baseless and should be soundly rejected by the Commission. If anything, the record in this proceeding is clear that the Company's T&D capital expenditures during the period covered by the 2005 Rate Plan have undergone no less, if not more, scrutiny than such expenditures are typically accorded in rate cases. (4127-4129, 4162).

As required by the 2005 Rate Plan, the Company's status reports provided detailed information on the Company's T&D capital projects (4102), including, among other things: forecast and actual program and project expenditures; explanations of program and project variances greater than the 15 percent from the previous estimates; completed project information; on-going project status, estimated completion date and up-to-date expenditures; and, for new projects, project descriptions and justification, cash flow requirements, and derivation of cost figures. (4106, Exhs. 141, 142 and 143).[59]

In addition, the Company met with Staff on a periodic basis each year to discuss its T&D construction program (4107), and numerous other times for further discussions on various aspects of the Company's infrastructure investments. (2557; 4107-4109; Exh. 338). With respect to the meetings held to follow-up on the Company's annual status filings, those meetings were

[59] The Company expects to file its fourth and final status report by January 31, 2008, which will cover actual expenditures made to December 31, 2007 and expected expenditures for the first three months of 2008.

preceded and followed by the submission of additional information by the Company in support of its status filings, as well as in response to Staff's requests for supplemental information. (Exhs. 350-355). In effect, Staff conducted an 'on-going' prudence review of the Company's capital investments, focusing not only on the Company's annual budgets, but also on the Company's latest five-year construction programs and the Company's historical expenditures going back at least three years. (4158-4159). In addition, where appropriate, such as for substation projects, Staff reviewed the detailed cost breakdown for each substation project, including material purchases, contract labor and overhead and contingencies. (4160).

Significantly, Staff understood that the 2005 Rate Plan contemplated that the Company would recover its deferred carrying charges relating to T&D capital expenditures subject only to Staff's review and oversight (4125), and the level of scrutiny undertaken by Staff was in line with that understanding and sufficiently rigorous to justify the recovery by the Company of its deferred carrying charges. (4127-4128). As stated by Staff, it viewed its primary mission in monitoring the Company's infrastructure investments as ensuring that funds were "being spent wisely and appropriately" (4127), and that the level of expenditures undertaken by the Company would enable it to provide "safe and reliable service at just and reasonable rates." (4171, 4176). When questioned by the bench, Staff confirmed that its review of the Company's expenditures during the period covered by 2005 Rate Plan was no less rigorous than its review of the Company's capital expenditures proposed in this proceeding or any other rate proceeding. (4127-4129, 4162). Staff also confirmed that its rigorous monitoring of the Company's capital investments covered both projects that had been previously reviewed by Staff in the context of the last electric rate proceeding as well as new projects proposed by the Company in its status reports, and focused not only on projects or programs that exceeded the Company's forecasted

expenditure levels, but also those that were within the Company's original estimates. (4128-4130). Finally, in response to Commissioner Curry, Staff testified that its periodic meetings with the Company to discuss the Company's capital expenditures were "very constructive" and that the Company satisfactorily addressed Staff's concerns with proposed spending levels on, and the necessity for, specific projects and programs. (4157-4158).

Given that the 2005 Rate Plan contemplated that, subject to Staff's oversight, the Company's T&D capital expenditures during the period covered by the 2005 Rate Plan would be deemed prudent and the Company would have to satisfy no other preconditions in order to recover its deferred costs (4125-4126), and given Staff's ongoing intense and diligent scrutiny of the Company infrastructure investments and the satisfactory manner in which the Company addressed any concerns raised by Staff, there was no reason for Staff to submit to the Commission or include in its testimony in this proceeding a full report on its review and oversight of the Company's expenditures, as purportedly expected by CPB. Nor is there any reasonable basis for CPB's purported expectation that Staff would have consulted or collaborated with other parties on its review of the Company's status filings or have presented summaries or analyses of its periodic meetings with Con Edison to the Commission. (4755-4756; 4769).

While the 2005 Rate Plan provided for at least eleven collaboratives on different initiatives, [60] the oversight over the Company's capital expenditures was not among those initiatives, but was instead delegated primarily to Staff.[61] Of course, CPB, as well as any other

[60] 2005 Rate Plan Order, pp. 108-109.
[61] Case No. 04-E-0572, Exh. 9, Responses 52 and 59. Although copies of the Company's status reports were, per the Joint Proposal, to be provided only to Signatory Parties, the Commission directed that it be provided to all interested parties. (2005 Rate Plan Order, p. 105). Nowhere, however, did the Joint Proposal, the 2005 Rate Plan or the 2005 Rate Plan Order contemplate a collaborative effort on the monitoring the Company's expenditures or any kind of consultations among the parties.

interested party, could have followed up on the Company's status reports with Staff or the Company, or both. CPB chose to sit on its hands while Staff reviewed voluminous information provided by the Company, conducted site visits, held numerous meetings with the Company and otherwise scrutinized the Company's expenditures vigorously and diligently (2557; 4102; 4107-4109, Exh. 141-143, 338, 350-355). CPB is hardly in a position to criticize Staff's review of the Company's expenditures, Staff's presentation of the oversight it conducted or its conclusion that the Company should be allowed full recovery of its deferred T&D capital costs.

C. Average Rate Base

The Company's Accounting Panel prepared projections of plant and depreciation reserve balances for the twelve months ending March 31, 2008 and March 31, 2009 (see Exhibits 85 and 86), appraising the impact of the current construction and retirement programs on the electric department's average rate base. (1320). The Accounting Panel explained that the average rate base includes an adjustment to align rate base with capitalization, often referred to as the Earnings Base/Capitalization ("EB/Cap") adjustment and that the EB/Cap adjustment was positive due to a number of factors, including the Company's net prepaid pension/OPEBs balance and the level of working capital. (1325). Staff and NYPA each take issue with the Company's EB/Cap Adjustment.

1. There Is No Basis for Staff's Removal of Prepaid Pension Costs from the Company's Earnings Base

Staff proposes to reduce the Company's earnings base by $142.0 million, which they attribute to prepaid pension expenses. Staff raises as concerns that the majority of the prepaid pension balance was amassed while the Company was off the Pension Policy Statement

(3615);[62] that a significant portion of the prepaid pension expense does not represent a cash investment by the Company (3615); and that the Company should not earn a cash return on a pension expense that is not associated with any cash outlay (3618) (i.e., the prepaid pension balance was not the direct result of the Company's making cash contributions to the pension fund in excess of its accumulated obligation, but the result of earnings of the pension fund that resulted in an accrual of a negative pension expense on the Company's books). Staff argues that while rates did reflect a credit for pension expense, the levels of prepaid pension expense recorded by the Company were in excess of the levels reflected in rates. (3616).

The Staff Accounting Panel calculated this adjustment by first determining that the Company's actual electric pension expense credit for the period April 1997 through March 2005 to be $276.6 million higher than the amounts provided for in rates; then reducing this amount to $229.3 million to reflect the customers' portion of shared earnings during two rate years of this period; and then adjusting the Company's capitalization by the net-of-tax amount of this difference (*i.e.*, $142.0 million). (3621-3622).

Staff's proposed adjustment should be rejected on several grounds. First, Staff's position that the prepaid pension expense was amassed while the Company was off the Pension Policy Statement fails to acknowledge that the Commission resolved this issue when it adopted the Joint Proposal that formed the basis of the currently effective electric rate plan. The Joint Proposal contains the following provisions (1391-1392):

> To settle certain issues raised in this proceeding, including issues related to the Company's pension and Other Post-Employment Benefits ("OPEB") costs and prospective application of the provisions of the Commission's Pension Policy Statement, the Company has agreed to provide a credit to customers of $100 million, as shown in 2005 Rate Plan Order, Appendix I, Appendix B, p. 5.

[62] Case No. 91-M-0890, Statement of Policy and Order Concerning the Accounting and Ratemaking for Pensions and Post Retirement Benefits Other Than Pensions (issued September 7, 1993) ("Pension Policy Statement").

> The electric pension/OPEB expense or credit recorded prior to April 1, 2005 (*i.e.*, prepaid pension balance) will not be eliminated from the Company's earnings base or capitalization for ratemaking purposes. 2005 Rate Plan Order, Appendix I, p. 14.

There could be no reasonable interpretation of these provisions, or the 2005 Rate Plan Order adopting the Joint Proposal containing these provisions, other than they resolved all issues regarding prepaid pension expense for the period prior to April 1, 2005, when the Company returned to the Pension Policy Statement, and that prospectively, the prepaid pension expense accrued prior to April 1, 2005, would remain part of the Company's earnings base or capitalization, including after the expiration of the currently effective rate plan.[63] The negative prepaid pension expense accrued during the period prior to April 1, 2005 was fully addressed by the Commission in the context of the Company's return to the Pension Policy Statement, as reflected in the agreement to credit customers $100 million and to retain the prepaid pension balance in the Company's earnings base.

Moreover, to consider again in this proceeding the inclusion of prepaid pension expense in rate base for the purpose of setting rates in this proceeding solely because this expense was amassed while the Company was off the Pension Policy Statement, would constitute retroactive ratemaking.[64] In calculating its proposed adjustment, the Staff Accounting Panel engages in a comparison of the Company's pension expenses for the period April 1, 1997 to April 1, 2005 to

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[63] The Company's gas and steam rate plans established in Case Nos. 03-G-1671 and 03-S-1672 also contained language resolving the prepaid pension issue. Order Adopting the Terms of a Joint Proposal (issued and effective September 27, 2004).

[64] *See, e.g.*, In Niagara Mohawk Power Co. v. Public Service Commission, 54 AD2d 255 (3d Dep't 1976), the Third Department articulated the prohibition against retroactive ratemaking:

> [I]t is reasonable and logical to conclude that no general authority to direct refunds was intended [by the legislature]. Furthermore, a perusal of case law reveals that our courts have held that the commission does not have the general power to order a utility to make reparation or refunds to its customers. The words reparation, refund and rebate all connote substantially the same thing. Rate making is a prospective and not a retrospective process.

54 A.D.2d at 257 (emphasis added).

the rate allowance for pension expenses. (3617-3618). While consideration of the Company's pension expenses for this past period may have been appropriate in the Company's last electric case in determining whether the Company should return to the Pension Policy Statement, there is no longer any credible basis for considering these historic expense levels in comparison to these historic rate allowances for the purpose of setting future rates. Doing so for these pension expenses would then call into question every element of the Company's income statement where a rate case estimate of sales, expenses, or taxes was different from actual results, affecting income and therefore capitalization, resulting in an earnings base that Staff would say requires adjustment. (1395).

Second, Staff argues that customers received no benefit from the difference between the negative pension credits reflected in rates and the higher negative pension expense booked by the Company, other than the customers' portion of shared earnings for two rate years during this prior period. Staff is again incorrect.

The growth in the pension investments achieved during the period the Company was off the Pension Policy Statement provides benefits to customers currently (*i.e.*, income from these investments reduces the current pension costs borne by customers). As indicated above, customers also received the benefit of a $100 million credit pursuant to the currently effective electric rate plan that is attributable to the resolution of the prepaid pension issue.

Moreover, Staff understates the benefits customers received from the shared earnings provision effective for the rate years ending March 31, 2003 and 2004, by interpreting the governing rate plans as providing for a 50/50 sharing of earnings between customers and the Company for earnings above the earnings sharing threshold. (1393). The governing rate plan, in

fact, provided for a 65/35 sharing between customers and the Company (1393);[65] the difference between Staff's 50/50 calculation and the 65/35 sharing established by the Global Settlement is an additional $59.3 million (see Exh. 97). In addition, Staff did not recognize that the Commission recently approved a Company petition to correct the amortization of deferred Asset Depreciation Range ("ADR") tax for calendar years 2000-2004, which results in customers receiving additional shared earnings for the rate years ending March 31, 2003 and 2004 of $9.029 million and $9.547 million, respectively.[66] (1394).

Finally, Staff's assertion that the negative pension credit above the amount reflected in rates did not create a cash financing requirement for the Company fails to recognize that the Company had to finance the $100 million credit to customers in resolution of the prepaid pension issue. (1394).

For all of the foregoing reasons, Staff's proposed adjustment should be rejected.

2. There Is No Basis for NYPA's Proposed Elimination of the Company's EB/Cap Adjustment

NYPA argues that the Company's EB/Cap adjustment should be eliminated and the Company determine its rate (earnings) base using either a lead lag study or NYPA's simplified working capital calculation, as shown on Exhibit 309 in lieu of the FERC 1/8 formula. NYPA's position should be rejected for the following reasons.

The NYPA Panel argues that the balance sheet should be used as a proxy to determine working capital requirements. (4645). However, the NYPA Panel contradicts itself in arguing that the EB/Cap adjustment "is a function of the entirety of the balance sheet." (4646). If the

[65] Case No. 00-M-0095, Opinion and Order Adopting Terms of Settlement, Subject to Modifications, Op. No. 00-14 (November 30, 2000), p. 28..

[66] Case No. 06-E-0990, Petition Of Consolidated Edison Company Of New York, Inc. For Disposition Of 2000 And Later Asset Depreciation Range (ADR) Deferred Tax Benefits Not Properly Accounted For By The Company, Memorandum Order (issued September 18, 2007)

balance sheet is an appropriate mechanism for calculating working capital, then it should be an appropriate mechanism for calculating the EB/Cap adjustment.[67]

The NYPA Panel also argues that the Company's use of the FERC 1/8 formula for purposes of calculating its working capital requirements, in lieu of conducting a lead-lag study, does not produce a result that is representative of the Company's real working capital requirements. (4642). The NYPA Panel claims that FERC has recently concluded that the 1/8 formula be viewed as a maximum or a guideline if no party objects to the absence of a lead lag study.

The Commission first noted its preference for the FERC 1/8 formula (known then as the FPC method) as opposed to the lead-lag approach (known then as the Mylott formula) in a 1970 Con Edison electric rate proceeding.[68] There the Commission stated:

> [T]he lag method of computing working capital has become so cumbersome as to make the time and expense of such a study disproportionate to whatever advantages the method may have in terms of accuracy. . . . We further agree with staff that we should use our decision in this case to discourage reliance upon the lag method in future cases.[69]

The Commission has, since that time, consistently continued to express its preference for the FERC method of computing an allowance for working capital, citing its opinion that this method is less complex and nearly as accurate.[70]

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[67] The NYPA Panel argues that capitalization exceeds rate base due to regulatory assets (*i.e.*, unrecognized pension and OPEB expenses), expresses the concern these regulatory assets are subject to wide swings due to market fluctuations, and will therefore have a material impact on the level of the Company's capitalization. (4647). NYPA's concern regarding the deferred pension/OPEB balances is unfounded because all gains / losses would be amortized over a 10 year period and would not impact capitalization (*i.e.*, income) until reflected in rates.
[68] Case No. 25342, Consolidated Edison Company of New York, Inc., Application by Electric Company for Authority to Increase Rates; Approved as Modified (issued August 12, 1970).
[69] 85 PUR 3d 276, 291.
[70] *See, e.g.*, Case Nos. 92-E-0875, 92-M-0605, Consolidated Edison Company of New York, Inc., Order Approving a Second-Year $251.2 Million Rate Increase for an Electric Utility Operating Under a Three-Year Rate Plan, Op. No. 93-7, (issued March 29, 1993); Case No. 28264, New York Telephone Company, Op. No. 83-11, (issued May 11, 1983); Case No. 26958, Brooklyn Union Case Company, Opinion and Order Determining Revenue Requirements of Natural Gas Company, Op. No. 76-25, (issued December 7, 1976); Case No. 26088, Niagara

A lead lag study can show the cash working capital requirements for a company to be significantly higher than the level resulting from the 1/8 formula. For example, National Fuel included a Lead Lag Study in its current base rate case filed in New York because it demonstrates that their working capital requirements under the lead lag methodology are comparable to the results they achieved using the 1/8 formula and adding to it their positive EB/Cap adjustment.[71] The Company's New Jersey affiliate, Rockland Electric Company, is required by statute in that State to file a lead lag study. The resulting working capital requirement approved in Rockland Electric's last rate case decided in 2006 was 50% higher using lead lag study than it would have been had Rockland Electric filed using the 1/8 FERC formula.

The allocation of NYPA's simplified balance sheet approach to calculating working capital shown on Exhibit 309, page 2, understates the working capital requirements for electric operations. First, the formula used to determine that allocation of working capital to electric eliminates electric production plant, and ignores future use electric plant and common utility plant allocable to electric operations to arrive at an allocation factor of 73.7%. Had these items been properly reflected, the allocation to electric would be 76.0%. While the overall change in the net working capital to electric is relatively small (*i.e.*, approximately $2 million), NYPA's calculation should reflect this change.

Second, in computing current liabilities, NYPA's witnesses included deferred income taxes associated with deferred fuel. This tax benefit was already reflected as rate base reduction on line 7 of the Company's rate base (see Exh. 94, page 1 of 2). The average deferred income

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Mohawk Power Corporation, Application by Electric Company for Authority to Increase Rates; Approved as Modified, (issued December 22, 1971).

[71] Case No. 07-G-0141, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service, testimony submitted by Regina Truitt.

tax balance associated with deferred fuel was $67 million during the historical period. Again NYPA's working capital calculation should be increased by this amount to eliminate this double count.

Third, NYPA's simplified balance sheet working capital calculation ignores the impact that cash payments for injury and damage claims previously reserved, and funding requirements for items such as the Company's pension/OPEB obligations, since their methodology completely ignores all financings. It should be noted that between December 2005 and December 2006 (the periods measured by NYPA), Con Edison's net plant increased by $1,332 million, while at the same time equity and debt (including short term obligations) outstanding grew by $1,375 million, an increase of $43 million. Here, too, NYPA's working capital calculation should be adjusted by this amount to recognize the need to finance increased operating requirements not captured in their simplified comparison of short term assets to short term liabilities.

Fourth, the calculations submitted by NYPA utilized data for the consolidated entity in some periods (*i.e.,* Consolidated Edison, Inc. ("CEI")) and for stand-alone New York operations *(i.e.*, Consolidated Edison Company of New York, Inc.) in other periods. That is, Exhibit 309, p. 1, indicates that a source of the data for this Exhibit were the 10-Q's of CEI. These 10-Q's contain both CEI and Con Edison data. A review of this publicly-available material shows that NYPA used CEI data for certain of the quarters and Con Edison data for the other quarters. Clearly the use of data from Con Edison's New York operations would be more appropriate since the CEI financials contain data from other regulated and non-regulated affiliates that is not relevant to this proceeding.

More significantly, NYPA used a five point average to make its calculation, utilizing data from December 2005, March 2006, June 2006, September 2006 and December 2006. As can be

seen from Exhibit 309, in doing so, NYPA sought to capture the December 2005 balance of $231 million, which is materially lower than the average balance for the 2006 period ($424 million). The proper calculation would be to use four points in time (*i.e.*, March 2006, June 2006, September 2006 and December 2006).[72] And even assuming that a five point average were appropriate, then the calculation should have been performed using one half of the December 2005 balance and one half of the December 2006 balance and dividing the total by four.

The impact of correcting NYPA's calculations to include production and common plant, eliminate deferred income taxes, reflect the growth in financing and utilize data from New York Operations would increase the working capital calculation submitted by NYPA from $385 million as shown on Exhibit 309 to $530 million. By comparison, the working capital calculation submitted by the Company in Exhibit 94 was $556 million. The variation between the $530 million and the $556 million can easily be attributed to the growth in operating expenses between the historical test year and the rate year. The use of historical financial data to calculate working capital requirements that are applicable to a future test year will result in an understatement of the working capital requirement when costs are increasing.

Finally, NYPA's criticism of the Company's EB/Cap adjustment because it results in a "negative number" is a red herring. That is, while the Company presented an EB/Cap adjustment to demonstrate that its pre-paid pension balance was properly included in its earnings base, and which resulted in the "negative number," the EB/Cap calculation is not necessary to demonstrate that fact. As discussed *supra* in response to Staff's arguments, the 2005 Rate Plan establishes the basis for retaining the pre-paid pension balance in earnings base for ratemaking purposes.

[72] As shown on page 1 of Exhibit 309, the balances for March, June, September, and December 2006 are $419 million, $260 million, $583 million, and $434 million, respectively.

D. CPB Plant in Service Adjustment

The CPB Panel claims that the Company understated the projected amount of retirements to plant in service. (3287). Their proposed adjustment should be rejected because it is based upon an erroneous calculation.

CPB states that the adjusted average percentage of retirements to plant in service in the 2004-2006 period was 13.19 percent. *(id.)* The CPB Panel then alleges that based on the Company's work papers, the Company projected retirements to plant in service in 2007 of $73,880,000 or 6.5 percent and in 2008, the Company projected retirements of $73,711,000 or 4.2 percent. (*id.*) CPB therefore argues that the Company has understated the retirement amount and recommends that the Commission apply the aforementioned 13.19 percent ratio to the actual plant in service level determined at the conclusion of this proceeding but applies no actual dollar value to this adjustment. (3288).

CPB misunderstands the Company's work papers. The projected level of retirements is much greater than the level derived by CPB and more in line with recent Con Edison history.

Exhibit 220 consists of two of the Company's work papers regarding the book cost of retirements. The first page of the Exhibit sets forth retirements for the period starting at January 2007 and continues through December 2007 and the second page sets forth retirements starting at January 2008 and continues through until December 2008. / (3355). The highlighted line on each page provides a total amount of retirements, which is the sum of the lines that include steam production, other production, and transmission & distribution, and electric's share of common plant (at 83 percent), which add up to approximately $201,589,000. (3355-3356; 3358-3360). The total of these items on the second page is $204,651,000. (3356-3357; 3360). Applying these

retirement amounts to plant in service produces a percentage of 14.19 percent for 2007 and a slightly lower percentage for 2008, 10.42 percent, due to several large plant additions in 2008.

CPB erred by multiplying the total figure on the line entitled "total common" (which appears below the highlighted line) of approximately $7.4 million per month, by 12 months, and then multiplying that total by the common plant allocation to electric of 83 percent to arrive at its $73 million figure. (3356). CPB thereby neglected to include in its calculation the retirements for steam production, other production, and transmission & distribution. Moreover, while not determinative of the proper projected retirement level, the Company's projected retirement levels are in line with the historical period referred to by CPB.

For the foregoing reasons, CPB's proposed adjustment is unnecessary and should be rejected.

III. OPERATING & MAINTENANCE EXPENSES

A portion of the Company's request for rate relief[73] in this proceeding relates to the continuation and expansion of various programs and the implementation of new programs, as well as escalation, normalization and other types of operating expense adjustments. These O&M programs comprise, among other things, the work the Company expects to perform on its T&D system and on its electric production equipment; the enhancements it intends to make to its customer operations area; the facilities it intends to repair and upgrade; the sites it intends to remediate; the facilities that it will support and protect as required by municipalities (*i.e.*, interference); and the research and development projects it intends to engage in to improve

[73] As noted earlier, the Company made two updates to its filing, a preliminary update in early August and a final update, with supporting testimony, as part of its September rebuttal filing. This brief reflects the September update information.

operations in the short and long term. The Company's filing includes hundreds of different programs and adjustments, many of which were unchallenged.

As explained below, the Company's proposed programs are necessary for Con Edison to provide safe and reliable service, and the associated projected costs and expenses are reasonable and necessary. The Commission should therefore adopt and fully reflect in the rates to be established in this proceeding these costs and expenses.

A. Program Changes

The Company's filing includes program changes[74] ranging from reinforcing both transmission and distribution cables to adding tax department personnel. These programs are described, explained and justified throughout the Company's presentation in this case in the direct and rebuttal testimony, exhibits, workpapers and discovery responses of the Company's witnesses.

Various parties proposed adjustments to these program changes which are discussed below.

1. Infrastructure O&M Spending

As noted in the Capital spending section, above, the Company's Infrastructure Investment Panel proposed numerous program changes aimed at either improving reliability, providing for public safety, supporting economic growth, hardening the system, taking advantage of advanced technology or improving existing processes. The Infrastructure Investment Panel described not only the capital work it intended to perform in the six categories mentioned above but similarly described and explained the supporting O&M work the Company intends to perform in those same categories. The Infrastructure Investment Panel projected

[74] Program changes can encompass a new program (something the Company has not undertaken before, *e.g.*, bird discouragers) or may entail an increase in the level of spending for an existing and continuing program over that in the historic year (*e.g.*, double pole program).

increased O&M expenditures totaling $195.2 million in RY1, $189.4 million in RY2 and $189.8 million in RY3. The various components of these amounts are discussed below.

In the Support Economic Growth category, Substation Operations projects RY1 O&M expenses of $4.7 million, RY2 expenses of $4.97 million and RY3 expenses of $5.5 million for the additional staffing needed (approximately 40 employees) for all the new facilities described in Section II above. (1727-1733; Exh. 122; Exh. 131). System and Transmission Operations projects an additional $100,000 for a district operator position to support the level of system work. (1742-1744; Exh. 125; Exh. 134). Electric Operations (Distribution System) projects approximately $1.7 million in RY1, $2.4 million in RY2 and $3.5 million in RY3 for programs aimed at supporting economic growth, such as customer surveys for load reductions and Smart Electric technologies. (Exh. 127; Exh. 135).

In the Improve System Reliability category, Substation Operations projects to expend approximately $39.7 million in RY1, $39.8 million in RY2, and $39.6 million in RY3 for various programs to maintain cable cooling and dynamic feeder rating systems that support the transfer of power and to provide increased operational flexibility. (1775-1781; Exh. 122; Exh. 131). System and Transmission Operations similarly plans to undertake a number of programs from painting towers to enhanced tree trimming, all aimed at improving reliability. (1789-1796; Exh. 125). Projected expenditures in RY1 are $6.1 million, RY2 are $6.1 million and RY3 are $5.8 million. Electric Operations plans four programs to Improve System Reliability, including making repairs to Unit substations and replacing automatic transfer switches. The Company projects to spend in this category $10.7 million in RY1, $10.4 million in RY2 and $10.3 million in RY3. (1811-1812; Exh. 127; Exh. 135).

In the Public Safety and Environmental Improvements category, Electric Operations plans to enhance the stray voltage mitigation programs, among other efforts, at a RY1 cost of approximately $73.6 million, RY2 cost of $66.2 million and RY3 cost of $67.4 million. (1812-1822, Exh. 127; Exh. 135). Turning to the environmental aspect of this category, Substation Operations plans to spend approximately $555,000 in each of the three rate years to reduce SF6 gas emissions and provide flame retardant clothing. (1828-1829; Exh. 122; Exh. 131). System and Transmission Operations intends to embark on three environmentally friendly programs, including performing additional manhole inspections and refurbishments, at an annual cost of $2.8 million. (1829-1833; Exh. 125; Exh. 134).

In the Storm Hardening and Response category, System and Transmission Operations intends to perform additional emergency drills, among other programs, at a projected O&M cost of $925,000 in each of RY1 and RY2 and $725,000 in RY3. (1851-1858; Exh. 125; Exh. 134). In the Electric Operations area, a number of programs are proposed, including removing double wood poles and danger trees as well as increasing existing line clearances. (1845-1851; Exh. 127; Exh. 135). The Storm Hardening and Response programs for Electric Operations are projected to cost $32.9 million in each of RY1 and RY2 and $31.2 million in RY3. (*id.)*

In the Advanced Technology category, Substations programs are projected to cost approximately $1.3 million in RY1, $1.3 million in RY2 and $1.4 million in RY3. (1878-1880; Exh. 122; Exh. 131). System and Transmission Operations have a number of programs associated with maintaining the Company's Alternate Energy Control Center ("AECC"), among other programs. (1870-1878; Exh. 125; Exh. 134). These costs are projected to be $6.5 million annually. (*id.*)

In the Process Improvement category, System and Transmission Operations projects O&M expenditures of $500,000 annually for RY1 through RY3. (1889-1891; Exh. 125; Exh. 134). Electric Operations proposes various work management and other programs at a projected O&M cost of $12.98 million in RY1, $13.8 million in RY2 and $13.8 million in RY3. (Exh. 127; Exh. 135).

The Staff Infrastructure Panel recommends no reduction to the funding for the Company's proposed O&M programs. They state that "our review of the Company's work papers and responses to our interrogatories regarding O&M programs demonstrate that the costs are appropriate and necessary." (4065). In stark contrast, CPB, Westchester, NYPA and NYC propose material reductions to the proposed funding for the Company's T&D infrastructure O&M programs. None of these proposals are based upon any project-specific study or analysis.

Westchester claims that overall, the Company should be limited to a $50 million increase to fund all proposed projects, including T&D infrastructure O&M programs, as well as other projects including, but not limited to, customer operations and environmental funding. (5451; 5455-5457). CPB, through its Panel of Schultz-DeRonne ("CPB Panel") makes various adjustments to O&M programs premised upon unfounded claims of a lack of supporting documentation and information or that the programs, if warranted, should be capitalized. (3238; 3262; 3266-3267; 3279). NYPA simply suggests that despite the fact that most of the programs have "merit," consideration should be given to decreasing the requested program changes by half. (4620). NYC's witness Arnett suggests a cap on the Company's O&M spending without setting any limit or establishing any basis for such cap. (4503-4504).

As explained below, the adjustments proposed by Westchester, NYC, CPB and NYC are without merit and should be rejected.[75]

Westchester arbitrarily proposes that the Company should be limited to a $50 million increase for what it terms "new" program changes. (5451; 5455-5457). Westchester claims that the "Company is proposing that ratepayers fund a host of new O&M programs ranging from the unimpressive – redesigning its website at a cost of $6.9 million – to the serious (but perhaps unnecessary at this time) gas turbine maintenance ($2.2 million)." (5455). Without any review or study, Westchester dismisses these programs, stating that "to balance these concerns, we believe that the Commission should moderate the rate effect of these costs by providing a more reasonable level of O&M expenses without ruling on each program." *(id.)*

Westchester proposed that the Company distribute the $50 million increase any way it sees fit (5495; 5497; 5501; 5506) and suggested that the Company pick and choose programs based on three criteria – they are reasonable, cost effective and within the $50 million budgetary constraint allowed by Westchester.[76] (5455). The unworkable nature of Westchester's proposal is not only clear on its face (in the context of the Company's being able to meet this budgetary constraint and still maintain the safety and reliability of its system), Westchester demonstrated during cross-examination that it does not intend for its proposal to reduce work in Westchester that Westchester otherwise expects the Company to perform. That is, when asked "if you are saying that one of the three major criteria for deciding how to spend the $50 million is budgetary constraints, and if it was in the Company's judgment that it ought not to increase its budget for tree trimming in Westchester, regardless of the experience of last year, would you agree that the

[75] Staff raises issues associated with the Company's stray voltage program but proposes no adjustment. The Company responds to Staff's concerns regarding this program later in this Brief.
[76] Westchester states that it is willing to apply an inflation adjustment to existing programs but the result of that adjustment is unclear. (5455-5456).

Company followed your instructions," the Panel responded "no." (5497). Westchester cannot have it both ways.

Moreover, without performing any analysis as to the costs the Company must incur to meet Commission mandates, Westchester stated that these budget constraints should not prevent the Company from implementing any recommendations from the Long Island City proceeding as they believed "it would be wise to implement those recommendations." (5494-5495).

Similarly, Westchester takes the unreasonable position that performance targets that may be continued as a result of this proceeding need not be adjusted even if the funding limitations proposed by Westchester do not enable the Company to fund the activities necessary to achieve those targets. (5501-5507). While Westchester's indifference to the Company's incurring a penalty is not surprising, it is evidence that the performance target associated with that penalty is not necessarily important to Westchester and should not be considered in the overall performance target framework.

Looking solely at the numbers, limiting the Company's increase to $50 million would mean that many programs, including Commission requirements, could not be performed since there would be no funding to do so. For example, Exhibit 127 details the Company's projected spending levels in the rate year for stray voltage and associated underground/overhead inspections. (Exh. 127). This Exhibit includes projected increases of $23.9 million for underground inspections, $5.7 million for stray voltage testing and $5.4 million for overhead inspections, all of which are required by Commission order in Case No. 04-M-0159. These three programs alone result in over $35 million of the $50 million in spending that Westchester would allow. Other mandated programs, like MGP remediation[77] or Local Law compliance, would

[77] As noted herein, the Company's MGP program alone is estimated at over $100 million in RY 1.

have $15 million to be split among them, leaving zero funding for all other Company requirements, including O&M associated with substations under construction, such as Parkview and Rockview, that are scheduled to come on line in the first rate year.

In its rebuttal testimony, Staff's Infrastructure Panel reviewed Westchester's adjustment, found it to be "unreasonable" and concluded that Westchester's cuts do "not insure customers will be provided with both safe and reliable service." (4067). More important, Staff, unlike Westchester, understood that the "O&M increases stem from requirements of Commission Orders, from O&M expenses related to capital projects, and from work Con Edison does according to its needs and specifications." (4067). Moreover, Staff appropriately rejects Westchester's unsubstantiated and arbitrary call for reductions, stating "Westchester's proposal is not reasonable in that it does not ensure customers will be provided with both safe and reliable service," and that Westchester's recommendation "to allow only a $50 million budget for programs changes is unreasonable." (4067).

In sum, the Company has demonstrated and justified the need for all of its O&M program changes. Westchester has not addressed, much less refuted, this justification.

For all of the foregoing reasons, Westchester's position should be dismissed.

a) <u>CPB's T&D Adjustments</u>

CPB's Panel proposes a number of adjustments totaling approximately $59 million to the Company's T&D O&M programs. CPB makes adjustments to Substation O&M programs, including telecommunications expenditures, Advanced Control Systems Group, Cable Cooling System Maintenance, Dynamic Feeder Rating System and Structural Integrity/Betterment; to System & Transmission Operations O&M programs, including Alternate Energy Control Center ("AECC") Equipment Support and Maintenance, New EMS System License,

Telecommunications Costs, Bird Discouragers and Improving Overhead Restoration Capability; and to programs for Supporting Economic Growth, Improving Reliability, Public Safety and Improvement, and Storm Hardening & Response categories of Electric Operations O&M programs.

In general, CPB makes several wide-ranging allegations for all of these adjustments. These allegations include the suggestion that although the Company provided over 10,000 pages of documents relating to its T&D programs during the discovery phase of the process, the Company did not provide sufficient historical and supporting data. In addition, the CPB Panel argues that some of the programs, if funded, should be capitalized, rather than expensed.

CPB had a full opportunity to pursue the information that they believed was necessary to evaluate the Company's proposed spending. In fact, in total, CPB propounded a total of 52 multi-part questions to the Company in the discovery portion of this proceeding. CPB did not choose to raise any objections, either formally or informally, during the discovery process, to the responses provided by the Company to CPB interrogatories. Accordingly, viewed against this backdrop, CPB's belated criticism of the Company's responses should be accorded no weight. CPB admits that its proposed adjustments stem from a lack of knowledge of its own making.[78] And moreover, CPB received copies of all of the discovery responses to Staff interrogatories, which Staff testified demonstrated that the Company's proposed O&M budget was "necessary to ensure a safe and reliable system." (4065). As such, CPB's complaints about the Company's responses to its discovery requests must be rejected.

(i) <u>Five Years of Data</u>

[78] Mr. Schultz attempts to distance himself from some of the Panel's adjustments, stating on cross that he is "relatively new at addressing issues in New York and there are some unfamiliarities that I have with what's allowed and what's not allowed." (3321). Such unfamiliarity does not provide a basis for adoption of improper adjustments. CPB must be held to the same standard as other persons participating in Commission proceedings.

CPB argues that the Company provided insufficient historical data for it to review for trending purposes, alleging that for Exhibit 214, Schedule 2, the Company failed to provide five years worth of data for the programs noted on the schedule. In fact, CPB claimed that in some instances, the Company did not provide historical information for even three years, *i.e.*, back to 2004. (3210).

When asked about this statement in discovery, CPB responded that it was referring to only four instances where the claimed information was not received out of hundreds of programs proposed by the Company. (3332, Exh. 217). One of these four programs is the five-year overhead inspection program, which CPB conceded on cross-examination was a program that the Company was not required to commence until January 2005. (3331). The second program was the underground inspection program, which similarly did not commence until January 2005 (which explains why information was unavailable prior to that time). (3331). As to the two other programs listed on Schedule 2 (which were not mentioned in the discovery response but noted as lacking information on the Exhibit), CPB also conceded that Stray Voltage and Local Law 26 (part of facilities), were not required until 2005 and 2004, respectively, and that the information for prior years was therefore unavailable. (3330-3331).

In addition, the Company's provision of three years of historical data is consistent with 16 NYCRR § 61.3(c)(i), which requires only three years worth of operating and historic data. If CPB felt an additional two years of data were necessary for its analysis of trending of expenses in a particular area(s), it was incumbent upon CPB to pursue this additional information with the Company.

In any event, the Company has demonstrated the need for its proposed programs and the absence of a trending analysis that CPB may or may not have performed and/or presented had it

requested and the Company provided additional data provides no basis to remove over $59 million worth of programs from the Company's filing.

As demonstrated above, CPB's broad characterization of the Company's failure to provide historical data is both misleading and inaccurate and therefore should be rejected.

(ii) Supporting Documents

CPB's next allegation is similarly dismissible. Here, CPB claims that the Company did not provide documents that supported its cost estimates for projects. (*See*, for example, 3211-3213; 3235). In its testimony, CPB announces that "supporting documentation" consists of invoices and quotes, not the voluminous series of work papers supplied by the Company that CPB claims are "just numbers on a piece of paper." (3211). CPB's position is simply incorrect.

In its rebuttal testimony, the Company's Infrastructure Investment Panel explained that the documents – invoices and quotes -- requested by CPB are not available at this time:

> … given the hundreds of projects covered by the billions of dollars at issue, providing details for each project in the Company's filing, rather than in response to interrogatories would make the Company's filing unmanageable. As to CPB's comment that it was looking for 'invoices, quotes, etc.", we would note that project quotes are established through a competitive bidding process conducted just prior to performing the actual work and would not be available until a qualified vendor has been selected. Since in many cases these projects will be initiated in 2008 and beyond, no project quotes would be available at this time. In addition, vendor quotes are typically commercially proprietary documents that are not available for release in a public forum.
>
> As to project invoices, they are only available upon commencement or completion of the work. Again, since these are future projects (2008) no invoices would be available at this time. (1977, emphasis in original).

On the stand in response to CPB's questioning, Mr. Longhi elaborated regarding the extensive documentation the Company provided in support of its case:

> We feel we properly support, adequately support the costs associated with these projects based on the information we provided. And between our original filing, our response to interrogatories, our updates, our studies, and our workpapers, I

> think just for the investment panel we provided about 10,000 pages of documentation. It's our view that that supports what your request is. (2054-2055).

Under continued cross-examination, Mr. Longhi again responded that the Company's documentation was more than adequate:

> We said we felt our 10,000 pages did support the cost. What we are saying here is that getting into invoices and details like that on literally thousands of projects would be unnecessary and unmanageable. (2055).

During their cross-examination, the Company's Accounting Panel provided a similar explanation as to the documentation provided in response to CPB discovery.

> Mr. Walters: And the questions asked for a document that supports the respective December straight time payroll amount shown, correct.
>
> Mr. Kane: Correct …
>
> Mr. Walters: Would you characterize the document that was provided as a supportive document?
>
> Mr. Kane: Yes.
>
> Mr. Walters: Would you provide a similar document to an entity such as the IRS if they requested you to legitimize an expensed item in your Company tax return?
>
> Mr. Kane: Generally, if the IRS issues a data request, they would get something similar to this. If they did an on-site audit, they would actually look at the payroll registers. This is a summary for the year (of the payroll registers). (1531-1532).[79]

CPB's assertions that the Company's documentation was lacking are simply incorrect. The Company's Infrastructure Investment Panel alone produced over 10,000 pages of data in support of the Company's proposals. They explained why the type of documentation sought by CPB (*e.g.*, invoices and vendor quotes) are not available at this time nor were they available during the discovery process. The Company's workpapers provide estimates of the projected

[79] Company witness Reyes also explained his view that the Company fully responded to CPB's request for documentation regarding the Company's variable pay plan. (1155-1161).

costs for the filing. Mr. Kane explained that the IRS reviews the same documents provided to CPB.

One other note, CPB's complaint about documentation is further diminished in that the CPB witness conceded that he "did review other responses" (3348) (*i.e.*, the same documents that Staff deemed to be adequate), but apparently ignored them in preparing for and developing testimony.

Accordingly, CPB's complaint about the absence of supporting documentation must be rejected.

(iii) <u>CPB's Lack of Action Is The Root of Its Adjustments</u>

As indicated above, CPB first complained about the Company's discovery responses in its testimony. Neither CPB nor its counsel called the Company to complain about or otherwise pursue the allegedly unresponsive answers. Except for isolated instances, they neither followed up on discovery responses nor made a single motion to the presiding ALJs or otherwise contacted the presiding ALJs to express their concern. In sum, CPB did nothing to address its complaints during the discovery process. (3335; 3345).

And not only did CPB wait until it filed its testimony to express its dissatisfaction with the Company's responses, CPB did not thereafter pursue additional information from the Company about its proposed infrastructure investments, including after the Company filed its rebuttal/update testimony.[80]

CPB's failure to pursue its concerns, particularly in light of the Company's extensive responses to discovery in this proceeding, provides no basis for the Commission to reject the Company's proposed infrastructure investments.

[80] In fact, CPB only asked seven questions on the rebuttal/update testimony. They were directed to Dr. Morin and limited to the cost of capital.

(iv) Other CPB Adjustments

CPB makes several other adjustments for reasons that are either without basis or are arbitrary.

CPB decreased spending of approximately $2.4 million for the AECC and two accompanying programs, New EMS System License and Telecommunications Costs, based upon its review of the workpapers and one discovery response. (3340; 3343; 3365-3367; 3370). In effect, CPB removed all of the spending for these programs. CPB testified that it was unsure of the purpose of the AECC (a backup facility to the Company's Energy Control Center) and that the Company had asked for the costs to build the AECC in Case No. 04-E-0572. (3343). On cross-examination, CPB conceded that there is merit to having an AECC location. (*id.)*.

CPB removed approximately fifty percent of the spending in the Improve Reliability category but recognizing that "the Company has substantial work to do to improve the reliability of its electric system," proposed the Company be permitted to defer expenditures above this amount up to the level that the Company projected to spend, *i.e.*, $10.699 million. (3243). While a reconciliation mechanism is an inadequate substitute for including in rates the appropriate requested level of costs, CPB provides no rationale why it singled out this one program for reconciliation when it similarly reduced funding for other programs that it acknowledged have merit (like those in the Supporting Economic Growth category (3320) without proposing any reconciliation. This treatment further demonstrates the overall arbitrariness of CPB's approach.

(v) CPB's Issue on Whether to Treat Costs as Capital or O&M

CPB also proposes that certain programs, if funded (*e.g.*, the Company's bird discourager program) should be capitalized. (3238). This proposal is based upon CPB's view that the

procedure upon which the Company relies to determine whether a cost should be capitalized or expensed is based on a Commission regulation that had been rescinded. (3369).[81] CPB is in error that the Company's procedure is no longer appropriate.

CPB's proposal fails to recognize that when the Commission regulation was rescinded, the Company was required to follow FERC's Uniform System of Accounts, which is the same as the Commission regulation that was rescinded. In fact, during the hearing, CPB admitted that the FERC and PSC Uniform System of Accounts were essentially the same documents. (3372). It "assumed" that the Company now follows the FERC Uniform System of Accounts, as mandated by the Commission, instead of the now repealed Commission Rules relating to the Uniform System of Accounts. (3371). CPB also agreed that the Company had to follow its rules related to capital versus expense (3357), that it must keep its books in line with either FERC or Commission rules consistently (3358), and that the Company is audited. (3358).

Since CPB has not alleged that the Company has not properly implemented its capital versus expense procedure, its objection must be rejected.[82]

In addition, CPB's speculation that the Company is attempting to accelerate recovery of these costs by treating them as O&M is equally without basis. In fact, it contradicts the speculation of CPB's other witness, Dr. Elfner, who argues that "utilities have a powerful incentive to undertake capital expenditures since it increases their rate base." (4620).

As explained, all of CPB's adjustments to T&D O&M program changes are improper and should be rejected.

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[81] In an interrogatory, the Company was asked to demonstrate why certain projects are considered O&M expenditures and not capital. The Company's response is included in Exh. 215.

[82] For these bird discouragers to be considered as capital items, the Company "would have to remove the existing poles and install bird discouragers together with new poles." (1982).

b) <u>NYPA's "Suggestion"</u>

NYPA states that the Company has requested a large increase in program changes, which it claims amounts to over $300 million. NYPA "opines" that the Company's budgets are "much, much too high" and appear to suggest that if "one-half the growth were cut, it would reduce the rate increase for Rate Year 1 by $150 million." (4620). On the other hand, NYPA states that "we do not doubt the merits of many, if not most, of the programs" but believe that to decrease the rate request, "programs should be drastically reduced." *(id.)* NYPA's suggestion fails for the same reasons as Westchester's draconian reductions. NYPA provides no analysis or assessment of the impact of its recommendation on any or all of the projects or programs that the Company has proposed. (1971-1972). Staff's Infrastructure Panel also rejected NYPA's O&M suggestions, noting that NYPA's approach is not "an adequate substitute for a thorough review of the Company's specific needs." (4069). NYPA's suggestion is not susceptible to reasonable implementation and must therefore be rejected.

c) <u>New York City's O&M Cap</u>

Mr. Arnett proposes that the Commission establish an O&M cap, similar to his proposal for a cap on capital spending (discussed above). (4504). Mr. Arnett's apparent sole reason for the cap is to develop a rate increase that "fairly balances safe and reliable service with just and reasonable rates." (*id.*) Mr. Arnett provides no other justification for his proposal nor does he provide any additional detail for its implementation.

Mr. Arnett's proposal for an O&M cap fails for the same reasons as the NYPA and Westchester proposals. It is not based upon any analysis. Nor does Mr. Arnett provide any recommendations as to which projects should be pursued, scaled back, deferred and/or eliminated. In rebuttal, the Staff Infrastructure Panel noted that Mr. Arnett also provided no

recommendation as to the level of the cap. (4062-4063). Accordingly, Mr. Arnett's proposal is not susceptible to reasonable implementation and should be rejected.

d) Staff's Stray Voltage Claims

While Staff's Infrastructure Panel does not make any adjustments to the Company's proposed O&M spending levels (4041), they claim that the Company's proposed funding increase for Public Safety programs, such as stray voltage testing, mobile detectors, and overhead and underground inspections, is "drastic" and was caused by "poor planning." (4043). Moreover, Staff also questions the 15 mobile stray voltage detection vehicles the Company has purchased to scan the streets (4044) and requests that the Company be required to file a report about the use of these vehicles within two months after the Commission issues an order on this rate filing. (4045). Despite these complaints, Staff does not make any adjustments to the stray voltage programs, stating that any issues relating to these programs will be addressed in Case No. 04-M-0159, the Electric Safety Standards proceeding.[83] (4043-4044). Staff then notes that if there are any changes to the Company's programs resulting from an order in that proceeding, the difference in funding should be credited to customers.[84] (*id.*). Staff's criticisms of the Company's stray voltage proposal does not comport with the facts.

The Commission's Safety Standards Order was issued in 2005 and since the tragic death of a pedestrian in January 2004, the Company has taken "unprecedented steps" to mitigate stray voltage conditions throughout its service territory. (1813). In fact, "there is no utility that has invested more to mitigate stray voltage." (*id.*) The Company has four main programs to detect

[83] Case No. 04-M-0159, Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems, Order Instituting Safety Standards (issued January 5, 2005) ("Safety Standards Order")
[84] Staff apparently assumes that the funding would go down, not up, as a result of this review.

stray voltage – stray voltage testing, mobile scans of the streets by the Sarnoff vehicles, underground inspections and overhead inspections. Each of these programs is addressed below.

(i) <u>Stray Voltage Testing</u>

Stray voltage testing is a program whereby the Company tests underground electric distribution structures, overhead wooden poles with metallic attachments and all New York City/municipality owned streetlights for stray voltage. (1814). Each one of these facilities is tested annually with the goal of mitigating stray voltage exposure. (*id.*) Testing equipment has improved in the past several years. Once a condition is detected, it is made safe until repairs can be effected.[85] (*id.*). In the historic year, the Company spent $6.8 million on this testing and projects to spend $12.5 million in the rate year. In its work papers, the Company explained that it expected significant increases in costs for these inspections. (Exh. 273). Exhibit 273, pages 80-81, sets forth the primary reasons for the increase in costs:

- an increase in per unit testing cost by contractors, which has effectively doubled since 2005;
- increased detection rate of stray voltage, which requires additional support to remedy the problem and individuals to stay at the location from the time the stray voltage is detected until it is fixed; and
- increased oversight by different departments, which was not included in the 2004 rate case request.

The stray voltage program has been developing since January 2004. As it has developed, the Company has gathered greater insight as to program requirements and now has additional information upon which to base its cost estimates, information that was unavailable when the program started. These estimates have been improved based on experience over the past several years and are not the result of "poor planning."

[85] This includes having a person stand guard over the site to protect against a pedestrian coming in contact with this facility.

(ii) Mobile Stray Voltage Vehicles and Testing

The next program is the mobile scans of the streets to check for stray voltage. The Company has purchased 15 Sarnoff vehicles since March 2005. These specially designed vehicles, which were the product of a collaborative effort between Con Edison and the Sarnoff Corporation, allow for rapid stray voltage testing of the underground system without the need to separately test each facility. (1815). These vehicles drive through the streets and check for stray voltage. As of the time of the initial filing in this proceeding, these vehicles had surveyed over 11,000 miles. (*id.*) They are used to survey the system after storms and survey areas prior to large events, such as the Thanksgiving Day parade and the Times Square New Years' Eve celebrations. (1815-1816). These vehicle inspections are an integral component of the Company's stray voltage mitigation efforts. The Company projects that the cost for this program will increase from $3.45 million in the historic year to $10.9 million in the rate year, much of which is due to the increased size of the fleet since 2006 and the resulting increase in the number of scans. *(id.)*

Staff complains that the Company's justification for such a large fleet (*i.e.*, that with 15 vehicles the Company would be able to scan the entire underground system in a week after a snowfall) is insufficient for such a high funding request. (4044). The Company respectfully disagrees. First, as explained in Exhibit 273 (p. 60), the number of electric shocks increase after a heavy snowfall with considerable snow accumulation and a significant amount of salt spread on the streets and sidewalks. It is important to survey facilities across the Company's system as soon as possible after such an event to address stray voltage and mitigate exposure to such conditions. Having the 15 vehicles on hand will allow a scan of the entire underground system to be completed in one week. (*id.)* In addition, the Company is moving towards doing eight

system scans per year, which is expected to reduce the stray voltage exposure by 90 percent. (Exh. 273, pp. 69, 71). Fifteen vehicles are required for this increased level of scanning.

The number of shocks to the public has declined, due in no small part to the use of the mobile stray voltage vehicles. The Company expects this trend to continue as the use of the vehicles increase. (1973).

As for Staff's requested report, it is unnecessary. The Company has thoroughly explained the need for these vehicles and their costs in this proceeding (Exh. 273, pp. 60-81) and has provided additional details in the on-going Electric Safety Standards proceeding. Another regulatory requirement to justify these vehicles is unduly burdensome and unnecessary.

(iii) <u>Underground and Overhead Inspections</u>

In compliance with the Commission's Safety Standards Order, the Company performs visual inspections of all underground and overhead facilities every five years. (1816). "These inspections require opening over 270,000 underground manholes, service boxes and transformer vaults to evaluate the condition of electrical equipment and repair any hazardous conditions." *(id.)* Similarly, the Company must inspect over 280,000 overhead poles. (*id.)* In the rate year, the Company projects an approximately $20 million increase in underground inspection costs and a $5.4 million increase in overhead inspection costs. Staff alleges that this is due to poor planning. (4043). This is not the case.

As was explained by the Company's Infrastructure Investment Panel, when the Company initially developed the program, it assumed that Company personnel would inspect a structure each time it was entered for routine work and that most of the structures on the system would be

visited in the five-year inspection period. This assumption turned out to be incorrect. By the end of 2006, 50 percent of all inspections were completed as part of the normal work process. (1972). This means that for the most part, many manholes are visited for routine work more than one time during the course of a year, leaving many other facilities that need to be inspected in a separate visit. (Exh. 273, pp. 86-87). Therefore, to meet the five-year goal for underground inspections, the Company must separately visit large numbers of facilities, something not previously reflected in the Company's spending patterns. (1817). This extra funding requirement is not the result of poor planning, rather it results from the knowledge gained as the program has developed during the past several years.

In the same vein, the Company explained that "no inspection of poles was required in 2006. Accordingly, the costs associated with 100 percent of the forecasted pole inspections, and repairs anticipated from these pole inspections, are incremental." (Exh. 215). That is because the entire overhead system was inspected in 2005. *(id.)* Going forward, the Company plans to inspect these facilities at the rate of 20 percent per year, on average, instead of all in one year. Accordingly, this additional spending is not the result of poor planning but rather it is a forward-looking approach aimed at spreading the costs of the inspection cycle over a number of years, by performing inspections over several years instead of in one year.

Accordingly, Staff's claims about the Company's stray voltage programs are simply incorrect.[86]

e) <u>Local 1-2 Staffing Issues</u>

Local 1-2 takes the position that the Company's internal staffing levels are inadequate; that the Company's use of outside contractors for work that its internal labor force is able to

[86] Similarly, CPB's adjustment for these programs should be rejected.

perform is excessive; that the Company's use of mutual aid workers in its underground system is inappropriate and should be discontinued; and that the Company's use of outside contractors raises safety and security concerns.

As explained below, Local 1-2's allegations are based upon speculation and unreasonable inference and are unquantified. Moreover, the Commission should not tolerate the Local 1-2's transparent and purely self-serving attempt to use the Commission's rate-setting process as a vehicle for an end run around the collective bargaining process.

(i) <u>Internal Staffing Levels Are Adequate</u>

Local 1-2 asks the Commission to draw the inference that the Company's internal staffing levels are too low based upon its identification of a single instance of alleged shoddy work by an outside contractor (5030), an allegation that the Company does not have a sufficient number of trouble-shooter crews (5031), and the Company's use of an outside contractor in connection with its stray voltage program. (5029-5030).

The Company's Infrastructure Investment Panel addressed Mr. Koda's unsubstantiated recommendations regarding the use of contractor labor, mutual assistance workers, and the security associated with contractor labor. They explained that the Company uses an appropriate and changing mix of skilled contractor labor in discharging its responsibilities for maintaining its system in a cost-effective manner; that this ever changing labor mix is dependent on the scope of planned construction endeavors; that adopting Local 1-2's recommendations would tend to limit the labor skill flexibility required in achieving efficiencies; and that when the Company uses outside contractors, the Company's terms and conditions for these types of contracts establish appropriate guidelines to which the contractors are subject that consider safety and environmental issues, among many others. (1987-1988).

As Mr. Miksad explained, with respect to the Company's distribution construction program, the Company is hiring internal employees on an accelerated basis and only five to ten percent of the Company's work on the distribution system is performed by contractors. (2195). Evidence of the Company's accelerated hiring program is further demonstrated by Company witness Mueller, who testifies to the Company's comprehensive efforts to maintain and add to the Company's internal workforce through aggressive hiring and training programs targeted to increasing the Company's internal workforce by more than 300 employees in each of 2008 and 2009. (Exh. 3). As to the excavation and the installation of conduit and installation of manholes, Mr. Miksad explained that practically "all of that sort of labor basically is contracted out and always has been. And those folks are just more efficient at that function. They do it for us and they do it for everyone else in the country." (2196-2197).

Mr. Longhi explained that "on the substation and transmission side, there's a lot more physical construction, excavation, trenching, erection of building facilities so that obviously we contract out. But if you carve out the electrical parts of that, that is also predominantly -- the vast majority of that is company labor probably along the same percent." (2195). As to whether Company vs. contractor labor is more costly, Mr. Longhi further explained that "it depends on the specific work. There's certain type of work that contractors are geared up to heavy construction and tend to be the most efficient way we can do that. Certainly on the other spectrum, with respect to specialty work on an electric system where our own employees would be much more efficient than, for example, a contractor coming in and doing it." (2195-2196).

Nor should the Commission give any weight to the notion that the Company's internal staffing levels are inadequate because of a single incident involving an outside contractor, even if true. Local 1-2 provides no evidence whatsoever that this incident was indicative of the

services provided by outside contractors, and no reasonable inference can or should be drawn from this single event.

Mr. Koda's allegation that the Company's staffing of troubleshooters is inadequate is similarly without merit. (5031). First, it bears mention that Mr. Koda's characterization of current staffing levels in his direct testimony is both misleading and inaccurate. That is, on cross-examination, Mr. Koda both accepted data provided to him by the Company in response to Local 1-2 Interrogatory No. 32 that the fewest number of troubleshooter crews in Brooklyn/Queens was two, and not one; that each crew was comprised of two troubleshooters, thereby constituting a minimum of four troubleshooters being on duty at any one time; that the Company was staffed with between 8 and 12 crews (*i.e.*, between 16 and 24 troubleshooters) in the Brooklyn/Queens region during the hours from 7:00 AM to 11:00 PM; and that if additional crews were needed in one part of the Company's service territory, that the Company would make additional troubleshooters available from its other regions. (5061-5063). In addition, Mr. Koda provides no analysis as to what the appropriate staffing levels for troubleshooters should be, but merely complains that the staffing levels are insufficient.

The same is true as respects Mr. Koda's claim that the Company's use of outside contractors in connection with its stray voltage testing program is indicative of the Company not having adequate crews available to address and repair its secondary system. (5031). This is clearly a non sequitur, since decisions on how to staff this component of the Company's stray voltage testimony program are clearly independent of the level of qualified personnel needed to address and repair secondary system failures. It is also another example of the Local 1-2's seeking to have the Company increase staffing of permanent, full-time, internal workers to perform "sporadic" work, with no economic analysis as to the cost of doing so.

That deficiency in Local 1-2's presentation is also evident in connection with its recommendation that the Company be precluded, prospectively, from using mutual assistance workers from other utilities during events affecting its underground system. (5027-5029). Not only would this conflict with the Commission's direction to the Company, implementing Staff recommendations 63 and 64 in its July 20, 2007 Order Implementing Outage Recommendations in Case No. 06-E-0894, et al., the basis for Local 1-2's position is inherently flawed and misleading. That is, the only basis in Mr. Koda's direct testimony for terminating the use of mutual assistance workers in the underground system prospectively is, again, a single incident of alleged poor work by a mutual assistance crew during the LIC event (for which there is no evidence that this was more than an isolated situation), and an unsupported allegation that "during the LIC outage, mutual assistance workers did not follow Con Edison's Policies, Procedures, and Specifications when doing work in the secondary system." (5028). On cross-examination, Mr. Koda acknowledged that he was not suggesting that the Company so directed mutual assistance workers, that his allegation was based upon the Company's inability to document that all such procedures were followed, and that, as a general proposition, the absence of documentation of an action does not mean the action was not taken. (5052-5054).

As to Mr. Koda's direct testimony that "[f]orcing the elimination of employees with a knowledge base acquired over years of service to satisfy a mandate which has no controls of costs incurred for outside contract labor is ludicrous" (5028-5029), Mr. Koda also acknowledged during cross-examination that he was not suggesting that the Company had eliminated any full-time employees for the purpose of relying upon mutual assistance workers during an event affecting its underground system. (5054-5055). In addition, Mr. Koda confirmed that he had not performed any type of economic analysis to determine the increased cost that the Company

would incur to provide the additional level of internal employees that would obviate the need to rely upon mutual assistance workers during an underground event. (5057).

(ii) **The Company Uses Skilled Professional Laborers To Work On Its Underground System**

Finally, Mr. Koda makes grossly unfounded accusations that the Company lacks concern with grid and personnel security, alleging that the Company has "abdicated its ownership responsibilities for its system and has unnecessarily exposed it to terrorist attack." (5035). This irresponsible allegation is not based upon any affirmative evidence of the Company's not implementing or complying with the myriad of actions it has undertaken to secure its system, in working with the U.S. Department of Homeland Security, the Commission and NERC, among others, or of the Company's not implementing or complying with its legal obligations under the Immigration Reform Act or any other federal or state law or regulation. Instead, Local 1-2 asks the Commission to draw these baseless inferences from the Company's responses to three Local 1-2 interrogatories for documentation of certain outside contractor information that the Company does not track. (5035).

Company witness Gonnella, Con Edison's Vice President of Construction, explained the process that the Company follows for qualifying vendors that work on the Company's facility so that only skilled professionals with proper credentials perform the work that is needed on the Company's electric system. Mr. Gonnella explained the Company's rigorous qualification process; that prospective contractors must first submit a Corporate Health and Safety Plan that is reviewed by the Company's Corporate Environmental Health and Safety ("EH&S") organization; the steps taken by the Company's Construction department to check out the contractor's credentials and prior work experience, to see that the contractor is qualified to perform the type of work; how the Company segregates the contractors it employs into various

areas of expertise and that more often than not, checks contractors' work in progress on other job sites to see if, indeed, what they are actually doing matches up with what they claim they do; that once Construction is satisfied with the contractor's resume, the EH&S organization is satisfied that the contractor has the proper health and safety credentials, and the Purchasing organization is satisfied that the contractor has the proper financials, the Company performs a Dun & Bradstreet review; only after these steps are completed, the contractor is placed on the Company's bidders list. (3163-3164).

Mr. Gonnella also explained the use of Company inspectors to oversee contractor work; that is, the Company has a series of Local 1-2 and management construction personnel, along with EH&S experts, who provide oversight to all the construction activity (3165); that for any project in a power plant or substation or commercial site, the craft labor typically is given a two-hour orientation to make sure they understand the parameters of the contractor's job specific Health and Safety Plan (3166); and that the craft labor must acknowledge in writing that they received this orientation, after which the Company provides the craft laborers identification numbers and implements an entry log procedure for each of our plant sites and a sign-in procedure at job-sites. (3161-3167; 3180). Mr. Gonnella also described the 24-person staff used by the Company to review the Health and Safety Plans (3169) and the training that the Company provides to its inspectors. (3175-3177).

On cross-examination, Mr. Gonnella confirmed that the Company's purchase orders require that all contractors conform with federal, state and local requirements, including compliance with the Immigration Reform Act and that the Company enforces compliance on an exception basis. (3173; 3182-3183). Mr. Gonnella explained that the Company has experienced personnel in the field and that if they see that a contractor is not complying with a particular law,

like OSHA, that Company inspectors are trained to spot such violations and take steps with the contractor to make corrections. (3173-74).

As respects undocumented workers, Mr. Gonnella testified that in his 40 years of experience with Con Edison, that he was not aware of anybody raising an issue as to the Company's use of undocumented workers, that if an issue had come up it would likely have been raised to his level of attention, and accordingly, there has been no basis for the Company to take steps to see that the contractors the Company retains are abiding by their contractual obligations to comply with laws relating to undocumented workers, like the Immigration Reform Act. (3174; 3178; 3183; 3186; 3188-3189). Moreover, Mr. Gonnella confirmed that the workers the contractor uses are skilled, union craft labor (albeit from a union other than Local 1-2), and that the craft labor retained to work on the Company's facilities go through the Contractor's safety orientation. (3178-3180; 3190).

On the basis of the foregoing, it is clear that Local 1-2's allegations are without reasonable basis and its recommendations that the Company's use of outside contractors be significantly reduced and that the Company be precluded from using mutual assistance labor in its underground system, should be rejected. In fact, one need look no further than Mr. Koda's rebuttal testimony, correctly arguing for the Commission to reject the City's "guestimated" three percent productivity adjustment as fatally flawed (5047-5048), to conclude that it would be unreasonable to seek to implement Mr. Koda's unquantified recommendation for the Company to increase its internal workforce, and rely less on outside contractors or mutual assistance workers.

2. Customer Service Spending

The Company, through its Customer Operations Panel, proposed changes to its outreach and education programs, enhancements to its Call Center, improvement in its field operations, expansion of its Mandatory Hourly Pricing ("MHP") program, continuation of its low income program, and changes to its retail access program and to four other programs (systems development, the Company's storm mobilization plan, changes to service fees, and bill redesign). The Company's proposed rate year O&M spending for these program changes is an increase of approximately $10 million. Capital spending associated with these program changes is an additional approximately $17 million. Proposed adjustments to the Company's rate case program changes are discussed below.

a) Outreach & Education

The Company proposed to increase outreach and education ("O&E") activities to address the challenges it faces in delivering key messages to its diverse customer population. The Company's customer base is very diverse in age, language and culture, and it benefits from information provided by a wide variety of sources. (803). To reach this heterogeneous customer population, the Company must communicate its important messages through the wide range of media familiar to its customers.

The proposed program also reflects the Company's response to Staff recommendations arising from the 2006 Long Island City and Westchester storm-related outages. (804). As a result of these events, Staff recommended that the Company "conduct a thorough evaluation of its outage communications program and develop an enhanced program to inform customers of

critical service-related information."[87] With heightened awareness of the need to improve its communications with its customers as a result of these events and this recommendation, the Company has both engaged in additional outreach during its current rate plan and proposed to increase its spending for outreach in the rate year. (804).

The Company is requesting funding to expand the vehicles used to provide information and in this way to increase customers' awareness and understanding of issues related to their electricity service, especially the Company's efforts to provide safe and reliable electricity delivery. The use of a variety of communication methods will help the Company communicate more effectively with its customers. (805). The Company's messages will also be broadened. Customers need to be made aware of the ways they can interact with the Company in the event of an outage, including by telephone and the Internet through the Con Edison website. The Company must also implement other Commission directives arising from the Westchester storm and Long Island City outages.

Specifically, funding is requested to increase the overall level of outreach and education through:

- Direct mail to reinforce messages to customers about power problems and other critical issues ($2.8 million);
- Advertising in a variety of media, including ethnic and community-based publications, especially to reach segments of the customer base who respond to languages other than English ($2 million);
- Improvements to the Company's Customer Central website[88] and an information campaign that will encourage customers and other stakeholders to go to the Customer Central website to view the educational messages and to use the tools available there ($1.345 million); and

[87] Case No. 06-E-0894, Department Of Public Service Staff Report On Its Investigation Of The July 2006 Equipment Failures And Power Outages In Con Edison's Long Island City Network In Queens County, New York (February 2007) ("Staff LIC Outage Report"), Recommendation 7.
[88] Customer Central is a section of Con Edison's corporate Web site and accessible from the Company's home page. Its content relates to and is developed by Customer Outreach.

- Enhancement to existing programs ($515,000).

(801-811; Exh. 49). Much of these proposed expenditures are intended to satisfy the Commission's outage-related directives.

(i) Staff's Opposition to Increased O&E Spending is Baseless

Staff opposes the Company's requested increase of $6.61 million. (3840). It proposes that the Company be granted an increase of $360,000 instead. (3841). Although the Commission is requiring the Company to enhance its communications with customers in connection with power outages, Staff's proposal is inadequate to provide the Company with sufficient funding for these communications and O&E enhancements. (841-842).

Although Staff agrees with the importance of outreach and education, Staff states that an increase of the magnitude requested "cannot be justified." (3840-3841). Staff contends that the Company's current O&E program has been very effective in getting its messages and information out to customers and that the addition of a number of enhancements "identified to improve communication during storm events" in consequence of the Long Island City network and Westchester storm outages will sufficiently improve the Company's day-to-day outreach efforts. (3841). On this basis, Staff proposes that "the Company reduce its proposed outreach and education budgets by approximately $6,250,000 to $3,900,000" for an increase of $360,000 over current program funding of $3,540,000. (3841). However, Staff conceded on cross-examination that the Commission had not addressed recovery of the costs for fulfillment of the outage-related directives[89] and that the Company had proposed to recover these costs through its

[89] Case No. 06-E-0894, Order Implementing Outage Recommendations (issued and effective July 20, 2007). ("Outage Report Order") Although this order was issued after the Company filed its rate request, the recommendations had been previously transmitted to the Company through the issuance of Staff reports on the Westchester storm and Long Island City outages in February 2007. *See* Staff LIC Outage Report; July and September 2006 Severe Storms: A Report on Con Edison's Performance (Feb. 2007) ("Staff Westchester Outage Reports").

proposed increase in O&E funding in this case. (3849-3850). For example, the Company plans to distribute by direct mail to all customers material on the topic of preparation for and coping with power problems at a cost of about $1.4 million. (Exh. 49; 3271).

In dismissing the bulk of the Company's proposal, Staff does not comment on the merits of the comprehensive programs that the Company presented. (841). On cross-examination of the Company's Customer Operations Panel, Staff counsel elicited the facts that gas O&E spending is approximately $1.3 million and that the Company has approximately three times the number of electric customers as gas customers. (879-880). From these facts, Staff counsel asked the Panel to agree that multiplying $1.3 million by three would produce $3.9 million. Implicitly, Staff counsel offered a post hoc justification for Staff's proposed increase to a rate year budget of approximately $1 per customer when he asked the Company's witness to confirm "that is just about what staff proposed for outreach and education in this [case]." (880). Staff's apparent reliance on the fact that the Company has approximately three times the number of electric customers as gas customers to justify proposing to allow the Company an increase of only $360,000 in O&E spending ignores all the differences between electric and gas service in the breadth of issues to be addressed.

Staff's methodology for determining what O&E funding should be allowed is problematic. Staff CSP fails to give due consideration to the range of issues for which the Company has a requirement to educate its hugely diverse stakeholder base. Issues affecting electric customers are more diverse than those experienced by gas customers and more complex as well. Electric-related issues range from power problems and public safety to life sustaining equipment to energy efficiency and conservation. For example, with respect to conservation, the message to gas customers is merely to moderate their heating needs. In comparison, electric

customers need to be concerned not only with the electrical requirements of all their appliances, refrigerators, lighting, computers, air conditioning, and electronic devices, but also when they use those electrically-operated items. Each type of equipment raises a different issue with respect to conservation.

The additional funding requested by the Company is required to reach all its customers on these important issues and to implement the Commission's requirements arising from the Westchester storm and Long Island City outages. Staff not only conceded that the Commission had not addressed recovery of the costs for fulfillment of its directives in its Outage Report Order but also that customers whose first language is something other than English are more likely to read and understand information in their native language and that the Company had requested funding for new and additional efforts to reach these customers. (3849-3850).

Above and beyond the Company's request for O&E funding (903), Staff witness Graves proposed that the Company undertake O&E with respect to the Company's proposal to expand its Mandatory Hourly Pricing ("MHP") program. His testimony does not indicate where the Company might obtain funding for these incremental activities. (3873). In discovery, he conceded that Staff did not provide for the Company's recovery of such costs in its adjustments to the Company's revenue requirement. (Exh. 53).

These inconsistent positions demonstrate the absence of any rational basis for disallowing the Company's O&E proposed funding. Further, although the Commission is requiring the Company to enhance its communications with customers in connection with power outages, Staff's proposal would deny the Company's request for funding for these communications. The mechanical application of a formula that was not mentioned in its testimony appears to be the only basis for Staff's proposed increase.

The Company's entire proposed increase should be allowed in the face of such non-substantive arguments.

(ii) <u>The Company Offered Sufficient Description of its Proposed Programs to Support its Requested Increase.</u>

CPB argues against the full amount of the requested funding on the grounds that it was unable to find sufficient justification in the Company's filing and in responses to its requests for supporting documentation. Based on this, CPB states that it cannot determine the reasonableness of the cost increases and that recovery of the full amount requested should not be allowed. (3269-3270). For the same reasons as explained above with respect to CPB's arguments against T&D and other funding, CPB's criticisms should be disregarded. (*see also* 846).

(iii) <u>Enhanced Communication is Critical to the Company's Responsibilities to its Customers.</u>

Staff's position on O&E is contradictory. Although it complements the Company for having a "well funded, well managed, and very effective" O&E effort, it refers to the fact that "enhancements were identified to improve communications during storm events." (3841). The outage-related directives are, in fact, broader than that, including Recommendation 7, which required the Company to "develop an enhanced <u>program</u> to inform customers of critical service-related information ... [and] provide Staff with an implementation plan for the redesigned outage communication <u>program</u>."[90] (emphasis added).

The Company's O&E budget addresses specific programs, with specific goals intended to meet Commission concerns about educating customers on power problems. (842). In fact, since this rate request was filed, the Commission confirmed Staff's recommendations that Con Edison

[90] Staff LIC Outage Report, App. A, p. 2.

enhance its communications with customers in connection with power outages.[91] These communications, as well as other critical energy-related messages, must be transmitted by means and in a manner that reaches the target audiences. In order for the Company to do this, it requires additional funding to implement enhanced and additional communication vehicles and communications in languages other than English. This involves a greater variety of messages and communications vehicles, such as ethnic newspapers, direct mail, and a web information campaign, and increased frequency of message publication.

Although it claims to support Company programs that educate customers and others, Staff refuses to recognize that the current funding is not adequate to cover the costs of these programs.

(iv) <u>CPB's Proposal That the Company Use Lower Cost Alternatives Disregards Many Factors Necessary to A Successful Outreach Effort.</u>

CPB believes that the Company should communicate information through lower-cost methods, such as bill inserts, the Company website, or other media sources. (3271). Thus, it proposes that direct mail be limited to some trial distributions to target audiences. (3271-3272). CPB also suggests that the Company website be used to greater extent. (3271). CPB proposes to adjust the O&E funding to $2.15 million, less than half the Company's request.

CPB's proposals ignore that the Company's survey determined that 39 percent of customers responding indicate that they preferred direct mail as a method to receive energy-related information (806; 847) and that the Company website is not considered the method of choice for customers receiving information. (847).

[91] Outage Report Order, pp. 9, 12-13, 17-18.

Moreover, contrary to its preference for a greater use of the Company website, among the budget items CPB proposed to delete were funds for website improvements and a web advertising campaign to direct customers to the Company's website. (3272). Customers need to be aware that the site and its services, information, and tools exist. Customers need to know how to access it. The Company noted, "Internet-based campaigns drive users, *i.e.*, our customers, to our web site and provide a clear channel to our educational messages located on 'customer central' and 'my account'" portions of that site. (807) And that requires O&E funding. (*id.*)

Con Edison operates in one of the country's most expensive media markets and one in which many recipients of media messages speak a language other than English. (810; 849). CPB's characterization of the Company's proposed media budget as "excessive" is without reasonable basis. The Company's proposal represents a modest media budget in this market, where a quarter-page advertisement in a newspaper can cost over $600,000. (*id.*) The market is not linguistically homogeneous. Staff agreed that the Company's service territory "encompasses a variety of populations that speak many different languages" and that there could be more than 20 languages spoken. (3848; 3854). The market presents many challenges to reach consumers in their native languages. This can be accomplished through ethnic- and community-based publications, and Con Edison is proposing to utilize these publications for the dissemination of energy-related information. (849-850).

In the face of the challenges presented the Company to communicate on a wide variety of important issues to an ever increasingly diverse population, in a place where there are a great many languages spoken, the Company's proposal is reasonable and provides for the efforts necessary to communicate with customers in its service area. Lower cost alternatives are not equivalent.

(v) **Staff's Proposal to Require Submission of Annual Program Plan is Unnecessary.**

The Staff has recommended that the Company be directed to develop annually a detailed public awareness, outreach and education program plan, setting forth program goals, objectives, messages, communication strategies, and effectiveness evaluation methodologies. This plan would be filed annually at least 90 days before the date of implementation and be reviewed through an expedited process through collaborative discussions among the Company, Staff and any other interested parties as to both program content and final budget for each initiative. (3841-3842).

The Company notes that, in response to Staff requests made twice a year, it has submitted details of its planned O&E program at the beginning of the summer and winter seasons. In addition, Staff shares its own outreach plans with the Company and other utilities. (843-844). This process has worked well in the past, keeping the parties informed of each other's plans and campaigns. Most importantly, this process has encouraged the utilities and Staff to plan their respective programs and campaigns well in advance of the season. Utilities can then secure media outlets early in a cost effective manner and plan for campaigns, and secure event space and cooperation from third parties in various programs. Because this process has worked well, no additional reporting requirement is necessary or should be required, particularly one that potentially adds administrative costs to the process at a time when Staff is suggesting that costs be decreased. (844-845).

The Company's proposed O&E funding will allow the Company to continue to address the Commission's outage-related directives as well as to increase customers' awareness and understanding of issues related to electric service, especially the Company's efforts to provide

safe and reliable energy delivery. For these reasons, the Company's entire request for O&E should be approved.

b) <u>Call Center Operation</u>

The Company's Customer Operations Panel testified in support of five programs to enhance Call Center operations (779-784):

- Call Center staffing at Company locations would be increased by 36 additional Customer Service Representatives ("CSRs") and two supervisors in order to address high levels of employee presence at training. (782).

- Call Center staff would be equipped to operate at remote locations through the addition of remote agent technology. (783-784).

- Speech recognition functionality of the Company's interactive voice response system would be enhanced to provide for additional applications to improve customer interactions with the system. (779-780).

- The automated outbound calling system, which currently has 24 production lines, would be increased by 48 lines to 72 lines to facilitate contact with customers after electrical outages regarding service restoration. (780-781).

- Uninterrupted power supply ("UPS") equipment would increase the reliability of Call Center equipment, particularly speech recognition, customer call recording, and quality monitoring services. (781-782).

Staff's Customer Service Panel opposed all Call Center enhancements with the exception of some increase in outbound calling lines and the addition of UPS equipment. (3829-3833).

(i) <u>The Call Center Staffing Increases Reflect the Company's Need For The Availability Of A Full Complement Of Trained CSRs</u>

Under the Company's proposal, Call Center staffing at Company locations would be increased by 36 additional Customer Service Representatives ("CSRs") and two supervisors in order to address high levels of employee presence at training. (782). Relying on the February 2007 reports prepared by the Department of Public Service Staff on the Long Island City network outage[92] and the Westchester outages,[93] the Staff 's Customer Service Panel claims that Con Edison's customer contact performance was satisfactory. (3830-3831). Therefore, according to Staff, the Company's request for additional Call Center Staffing is unnecessary. (3830-3831). Staff is incorrect.

First, Staff evaluates the Company's request in the context of the numbers of CSRs required to provide a satisfactory response during an event, like an outage. These CSRs will be available for duty during such events but that is not the basis for the Company's request. (835). As the Company's testimony made clear, the Company's staffing request is intended to support routine operations; it is not focused on emergency calls. (834). Less than five percent of the total calls the Company receives each year are emergency-related. (*id.*)

Second, these additional CSRs are needed to accommodate the training of new employees to fill vacancies resulting from a high rate of attrition. (*id.*) The additional employees will enable to Company to have a full complement of CSRs in the Call Center while accommodating the training schedules of new hires. (835).

(ii) <u>Remote Agent Technology</u>

The Company proposed to outfit some CSRs with laptop computers and communications services to allow them to work at remote locations as a means to address business continuity and workforce diversity. (783-784). The technology would be phased-in with groups of CSRs over

[92] Staff LIC Outage Report, p. 42.
[93] Staff Westchester Outage Report, p. 55.

a three-year period until 150 remote positions are established. (783). Staff dismisses the Company's proposal to use remote agent technology because it incorrectly associates this technology with the proposal for increased CSR staffing. (3831-3832).

The Company's proposal to utilize remote agent technology is independent of the Company's increased staffing request and does not decrease the need for Call Center staffing discussed above. (835).

Remote agent technology is a key ingredient in the Company's business continuity strategy. (*id.*) This technology is expected to facilitate the Company's handling of customer calls during emergencies and other times when staffing demands surge by allowing CSRs to work away from Company locations when, for instance, extraordinary conditions might make commuting difficult. (*id.*) It also enables greater flexibility in staffing and broadens the pool of prospective employees that can be recruited, or retained, for positions in the Call Center. (835-836). The Company noted that remote agent technology does not involve additional personnel, "just the same people being redeployed in different time frames" and "would allow us to get people on the phones at remote locations more quickly." (862).

The Company should be permitted to implement this technology, which offers promise of flexibility for customer contact requirements, particularly in extraordinary circumstances. The planned phase-in will allow the Company to review and modify the project as implementation proceeds.

(iii) <u>Speech Recognition</u>

The Company proposed to enhance the speech recognition functionality of the Company's interactive voice response ("IVR") system. The enhancements would include

expanding the vocabulary available on the system and creating new applications that would improve customer interactions with the Company through this system. (779-780).

Staff characterizes the enhancement of the Company's speech recognition system as a non-essential investment and suggests that a less costly touch-pad based solution be used instead. (3832). Staff Customer Service Panel's position is driven by its erroneous assumption regarding the cost of speech recognition system enhancements. (3832). On cross-examination, Staff conceded that the $500,000 capital cost projected by the Company over three years as stated in the Company testimony is much smaller than the $2.08 million rate year cost stated in Staff's testimony. (3832; 3852).

The Company has already funded and initiated the selection and installation of a speech recognition solution to replace its current IVR system (836), which is approaching the end of its useful life. The Company's proposal relates to the maintenance and enhancement of this system, to maintain customer satisfaction with the service that they receive through this system. (*id.*) To do so, the Company must provide for continued operation of the system and must develop comprehensive and intuitive voice-automated applications. (*id.*)

(iv) <u>Outbound Call Lines</u>

The Company proposed to increase the number of outbound telephone lines by 48 to 72 lines in order to facilitate telephone contact with customers during and following outages, specifically to notify customers of the estimated time of service restoration and verify with them that service has been restored following an outage. (781; 837). By testifying that some increase in the number of outbound lines should be allowed, Staff clearly recognizes the importance of this facility. However, Staff 's Customer Service Panel mischaracterizes the Company's need

for additional outbound lines by referring to the requirement that the Company establish direct communications with critical care facilities. (3832-3833).

Beyond asserting that the Company has managed in the past with its existing 24 outbound lines (3851), it offers no rationale for selecting 24 as the number of additional lines by which the Company should be allowed to increase its existing system. The absence of any basis for its recommendation became very clear in its concessions on cross-examination that Staff was unfamiliar with the number or duration of calls the Company might have to make at any given time or the time necessary for dialing, waiting for a connection to be made, and waiting for an answer on each of these calls. (3851).

In contrast, the Company's proposal was based on a careful review of the requirements of the Emergency Control System, and specifically the number of lines required to support peak outbound requirements. (837). The Company must be prepared for a worst-case scenario, such as a system-wide event, not just a storm in the Westchester area, and should not be denied the funding to expand the functionality of this system as in its reasoned judgment is required.

c) <u>Improvement in Field Operations</u>

In its direct testimony, the Company's Customer Operations Panel proposed to increase Field Operations staffing assigned to read demand metered accounts. Access to these accounts on the regularly scheduled date has become increasingly difficult and multiple attempts at meter reading are needed. Also, the number of demand meters has been increasing. This additional staffing will assist the Company in obtaining actual meter readings. (792). Eight Customer Field Representatives ("CFRs") are requested for this activity. (839; Exh. 51).

The Company also proposed to increase Field Operations staffing assigned to perform field visits to meters where consumption is reported on inactive accounts. The purpose of these

visits is to identify a new customer of record and resolve, as between old and new occupants, liability for service that has been used. With increasing numbers of customers using service without properly notifying the Company, the Company needs additional resources to investigate and resolve these accounts. (793). Seven CFRs are requested for this activity. (0839; Exh. 51).

Staff claims that most of the projected work volume of the proposed CFRs is for the fielding of meters where consumption is reported on inactive accounts. (3839-3840). This is not correct. In fact, as described above, eight of the additional CFRs requested are needed to support the increase of demand meter readings and only seven of the additional CFRs requested are needed to support the increase of inactive account field visits. (839).

Staff also posits that the fielding of meters where consumption is reported on inactive accounts protects the Company's revenues, which would otherwise be unbilled if a new customer is not identified and/or liability for service between old and new customer not resolved. (3840). Staff believes that these new positions therefore should be self-funding and that any incremental O&M amounts added to revenue requirement represent unneeded costs for CFRs in excess of additional revenues they are able to recover. (*id.*) Based on this, Staff recommends that the entire proposal for additional CFRs be rejected. (*id.*)

As the Company explained, by their very nature these inactive meters are difficult to resolve and the potential revenues that may be produced by this activity are speculative at best. (840). In about 85 percent of cases when inactive account field visits are made, the Company cannot establish responsibility for the past usage and can only put the customer on record on a prospective basis. (873). Without identification of the previous user, the Company is unable to bill for the amount of consumption that had been used, and, therefore, the Company cannot collect any revenue in compensation for that usage. (872-873). Service to such locations may be

terminated, depending on the CFR's ability to determine who is responsible for the account when the field visit is made. (872). In cases where the Company may be able to identify the party responsible for past consumption and bill the customer for that consumption, it is frequently unable to collect those charges. (873). And separate and apart from the revenue implications of these efforts, inactive meters need to be addressed to the benefit of all legitimate stakeholders. The Company has an obligation to the community to take steps to protect the integrity of our infrastructure and to identify those who may be improperly utilizing our service. (840).

Staff also questioned why the Company is seeking to increase the meter readers at the same time that it is seeking to implement AMI, a program that the Company forecasts would result in the reduction of meter readers. (875-876). As the Company explained, the meter readers needed to support these activities, although similar in title, are what the Company refers to as nonroutine employees (896), that is CFRs that perform activities other than reading meters on the scheduled reading date. (896-897). Therefore, although the Company expects to reduce its meter reading forces as a result of AMI, CFRs will still be needed to perform nonroutine meter reading activities. (896-897). In addition, given Staff's opposition to addressing the Company's AMI proposal in this proceeding and the uncertainty concerning when the Commission will address the Company's proposal in the generic AMI proceeding, any assumption about meter-reading savings due to AMI should be considered speculative at best.

Further, the Company clarified that the implementation of AMI will not resolve issues related to consumption used at inactive accounts. Although it will allow the Company to retrieve meter readings, AMI will not help the Company in determining responsibility for an account or putting new customers on record. (897-898).

Staff's assumption that these positions should be self-funding from the employees' collection activities is flawed. The Company established that it engages in these activities only in part for the purpose of revenue collection and for the far more important reason of endeavoring to assure that demand meters are read timely and that customer responsibility is determined when meters are advancing in the absence of a customer of record. (840).

For the reasons stated above, the Company's proposal to increase Field Operations staffing should be approved.

d) <u>Mandatory Hourly Pricing</u>

In its initial testimony, the Company proposed to expand its Mandatory Hourly Pricing Program ("MHP") to include customers with maximum monthly demands greater than 500 kW. (771-779). To do so, the Company projects to spend in total approximately $6.1 million in calendar years 2008-2009 for meter and meter installation costs and for integration into the Company's MDMS system, discussed above.[94] (778). This MHP expansion will have associated O&M expenditures of nearly $1 million for ongoing associated communication requirements. (*id.)*

The Company initiated its MHP program in the context of a Commission proceeding that sought to:

> realize the benefits of reducing the electric system's peak period demand and shifting load to off-peak, less expensive time periods. The benefits for customers were described [in a prior order in this proceeding] as potential reductions to peak period prices, enhanced peak period reliability, wholesale market power mitigation, and a reduction in New York State's dependence on natural gas fueled generation. In the face of rising electric prices caused by rising natural gas prices, which accelerated in the aftermath of Hurricanes Katrina and Rita, we identified a

[94] The cost for MDMS is reflected in the AMI program costs, which are addressed in section II of this Brief.

> need to move expeditiously toward hourly pricing for the State's largest customers.[95]

These goals are just as important to New York today as they were when the Commission enunciated them in 2006, and they underlie the Company's proposal to increase the number of customers taking service at hourly commodity rates.

Regarding the MHP program details, the Company proposed to implement this expansion in two phases – for customers with demand greater than 1000 kW up to and including 1500 kW beginning with bills having a "from date" on or after January 1, 2009 and for customers with demand greater than 500 up to and including 1000 kW beginning with bills having a "from date" on or after January 1, 2010. (774-775). The Company plans to implement the billing for these customers after interval meters, which are necessary for this billing (3880), are installed. The Company also proposed a special charge of $1,000 to be added to the bills of customers who deny the Company access to change the meter. (777).

Noting that the Company is not obligated to undertake these programs at this time (3859, 3888), Staff witness Graves offered several changes to the Company's proposal. First, he suggested that the first phase be delayed through a summer period in order for customers to be able to review at least six months of load data prior to being placed on MHP. (3863). Regarding the second phase, he would maintain the January 2010 implementation date but suggested customers have access to this data for a year prior to being placed on MHP. (*id.*) Second, he suggested that the Company engage in additional outreach and education for these programs, including providing a newsletter to customers, for which he did not provide any rate relief. (3873; Exh. 53). Third, he claimed that the $1,000 special charge was not needed. (3874-3875).

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[95] Case No. 03-E-0641, Proceeding on Motion of the Commission Regarding Expedited Imiplementation of Mandatory Hourly Pricing for Commodity Service, Order Denying Petitions for Rehearing and Clarification in Part and Adopting Mandatory Hourly Pricing Requirements (April 24, 2006) ("MHP Rehearing Order"), pp. 1-2.

Finally, he suggested that only MHP customers bear the burden of the metering costs associated with MHP service. (3876).

As to Mr. Graves' request to provide additional data to eligible customers, the Customer Operations Panel explained in its rebuttal testimony that this would delay the implementation of MHP for these customers. (827). For example, the Customer Operations Panel estimated that:

> expansion of MHP billing would have to be delayed for customers over 1 MW from January 2009 until no earlier than Fall 2009. Thus, the earliest summer period that MHP billing would be in effect for customers over 1 MW would be Summer 2010. Likewise, for customers over 500 kW, MHP billing would be delayed with Summer 2011 the earliest summer period that MHP billing would be in effect. (827).

The Company opposes Mr. Graves' additional information suggestion. Any modest incremental benefit associated with the provision of additional data would be far outweighed by the detriments of delaying MHP. Tellingly, the Commission does not require that customers receive access to this information prior to being transferred to MHP. (825). As noted, the Commission identified a need two years ago to move the state's largest electric customers to hourly pricing rates "expeditiously" so that they receive accurate price signals. (825-826). Mr. Graves' proposal for a period during which customers can review data but not be billed on the basis of that data will only delay the implementation of hourly pricing for these customers in Con Edison's service territory and the date when these customers can begin to see and respond to hourly pricing. Since customers cannot receive the information until meters are installed (and most of the population affected needs interval meters), requiring this information would delay the implementation of both phases of this program – a result neither the Company nor the Commission (as noted in its prior orders) desires. As such, Mr. Graves' proposal should not be adopted. If the Commission nonetheless determines that customers should have access to data before being required to switch to MHP, then the Commission should not mandate a specific

start date for MHP billing of these customers. Instead, the program should not start until after all the meters are installed[96] and the Company has had an adequate opportunity to provide the data required. During cross-examination, Mr. Graves agreed to this concept. (3888-3890).

Mr. Graves did not include any additional rate relief for his second suggestion, *i.e.*, outreach and education for the MHP customers, including a newsletter. (Exh. 53). The Customer Operations Panel testified that Mr. Graves' proposed outreach and education program was "excessive." (828).

Mr. Graves posited that the Company should not be permitted to assess a $1,000 special charge monthly to these customers who deny the Company access to replace their meters. (3873-3875). His position was based on the fact that a small fraction of customers refused access for meter exchanges in the residential time-of-use program back in 1992. He extrapolates that only one customer would deny access in the MHP program expansion. (3874). He additionally notes that National Grid did not experience any problems of meter access in its recent rollout of advanced meters and that customers have the option of switching to an ESCO instead of being placed on MHP. (3875). Mr. Graves' optimistic position does not withstand scrutiny.

First, the Commission directed the utilities to provide interval meters for all customers in the usage range subject to MHP, not only fully-bundled customers.[97] Thus, if Staff's suggestion that customers can opt to take retail access service was intended to indicate the utility would be relieved of the requirement to install an interval meter for such customers, the suggestion is clearly incorrect. The Company's expansion of MHP must take into account the time necessary

[96] The current schedule is for all the meters to be installed by January 2010 for the second phase.
[97] MHP Rehearing Order, p. 17.

for it to install interval meters on the service of all customers in these groups that do not now have interval meters.

Second, in rebuttal, the Customer Operations Panel explained their belief that the number of cases where the fee would be imposed would be "very small" but that a fee "is necessary to encourage all customers to provide timely access." (830). Absent such a fee, the Company would be "without any leverage to encourage" customers to cooperate because some customers would have a "direct interest in delaying the meter conversion." (831). Mr. Graves fails to provide an adequate response to this "real world" concern.

MHP is a mandatory program (3879-3880) for which customers must have the proper meter. Mr. Graves agreed that "a large number" of meters in the Con Edison service territory "are inside," meaning that the Company must be allowed access to change the meter and if customers fail to let the Company in, the meter cannot be changed. (3881). Mr. Graves did not know if the Company had any issues with customers providing access for changing meters as part of its deployment of AMR in Westchester. (3882). The Company has encountered customers who have continuously refused the Company access. (*id.*) In fact, the Commission has at least two pending customer complaints with the Commission relating to this program. (3883-3884). Equally important, Mr. Graves questioned the relevance to the issue of access denial of meter installation in the AMR pilot in Westchester because he assumed that the pilot involved replacing the meters of only residential customers. (*id.*) He subsequently acknowledged that the Company is installing or has installed AMR for *all* customers in the Rye and Peekskill areas. (3884-3885). This renders the Company's Westchester experience very relevant to the Company's assumption that more than one customer required to be transferred to the MHP expansion program will refuse the Company access to change the meter. Therefore, it

is entirely proper to have a special charge in the event that customers failed to permit access. A customer cannot receive MHP – a program desired by the Commission to send pricing signals and affect customer energy usage – absent a meter.

Mr. Graves' final point is that meter costs should be "recovered via a tariffed incremental meter charge in conformance with the Commission's MHP Rehearing Order." (3876). Mr. Graves claims that National Grid made such a proposal, which was approved by the Commission. (*id.*) In rebuttal, the Customer Operations Panel argued that "all MHP costs, including metering costs," should be charged to and recovered via delivery rates because "MHP is deemed to benefit all customers." (832).

The Panel took issue with Mr. Graves' characterization of the Commission's approach to the recovery of metering costs in that Order, noting that MHP customers were not required to bear the burden alone, "only that they not bear it as a lump sum, up-front charge." (*id.*) The Company is a different utility and has different cost recovery mechanisms than National Grid. Simply because National Grid does it this way does not mean that Con Edison needs to have the same recovery methods. All customers benefit from the customers taking MHP because it may result in lower market prices and all customers should be required to pay for these metering costs. (*id.*). Mr. Graves' suggestion is not required by the MHP Rehearing Order.

As such, Mr. Graves' suggestions for MHP should be dismissed and the Company's proposal implemented.

e) <u>Street Light Billing System</u>

City witness Galgano complained that the Company has not completed an electronic register for street light billing. (5075-5076). Under the existing rate plan, the Company, NYC

and NYPA were to work together to develop such a system.[98] The Customer Operations Panel agrees that the system is not yet in use (852) but explained that the some of the delays are generally attributable to the Company's working toward completing the beyond-the-original scope changes requested by NYC and that NYC has been deficient "at times." (852). On cross-examination, Mr. Galgano conceded that the delays in the system can also be attributed to NYC and NYC was also deficient at times. (5079).

As the Customer Operations Panel further explained, completion of this system is still expected in December 2007. (852-853).

f) <u>Low Income Program</u>

The Company proposed to continue the low income program currently in effect under the existing rate plan.[99] (789-790). Under this program, participating customers pay a reduced Customer Charge. A customer is eligible to participate if he or she receives Public Assistance, Supplemental Security Income or Food Stamps or received a benefit under the Home Energy Assistance Program in the last 12 months. Funding for the program is currently $12.5 million annually. (789). The Company proposed to continue the same level of funding, which would provide approximately 245,000 customers a reduction of $4.25 per month in the proposed Customer Charge. (789-790). Customers already on the program would not have to reapply in the rate year to receive the discount. (790).

Staff proposed an increase in the funding for the program to $24.9 million annually. This would permit the Company to freeze the Customer Charge for participating customers at $6.50 per month, a discount of $8.71 from the Company's proposed Customer Charge of $15.21.

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[98] 2005 Rate Plan Order, App. I, pp. 59-60.

[99] The Company's program under the existing rate plan also provides for the Company to waive the reconnection charge for participating customers whose service is terminated for non-payment and then restored; the Company did not propose to continue this benefit in the rate year.

(3838). Staff justified the additional funding and higher discount level as "reasonable" "given the rising cost of electricity, the impact of electricity costs on low income customers, and the potential for offsetting benefits to the Company and all customers." (3839).

While the Company does not dispute that electric costs have risen, there is nothing in the record that establishes what is "reasonable" in terms of funding. Staff relies on "[e]vidence from a variety of sources" as the basis for its conclusion that the discount should be greater. (3834-3835). However, these sources are not described sufficiently to allow the reader to determine if the sources distinguish energy costs specific to the Company's service territory or whether the analysis assumes that electricity is relied on for heating, factors important in determining whether these sources support Staff's position. Staff leans heavily on the cost to consumers of using electricity for heating in "poorly maintained and energy inefficient housing" in its conclusion that low income customers require financial assistance through programs such as utility rate discounts. (3835).

Staff also cites the Commission's 2005 increase in SBC funding devoted to low income customers from $11 million to more than $38 million annually. (3837). The record is barren of evidence that the housing of customers eligible to participate in the Company's low income program can be described in the terms Staff uses. The record is similarly barren of any reason that Con Edison's customers, who already provide funding for SBC programs, should bear twice the cost of the low income program they are currently supporting, a sum that is nearly two-thirds of the SBC charges all utility customers around the state are required to pay for low income programs operated by NYSERDA. There is, thus, nothing reasonable about the Staff's proposal, and it should be rejected.

g) Retail Access

The Company initiated several retail access-related programs during the 2005 Rate Plan, including Power*Move*; its ESCO referral program; Market Match, by which customers can request supply proposals from ESCOs through a Company website; and the Purchase of Receivables ("POR") program by which Con Edison purchases ESCO receivables in connection with utility consolidated billing of retail access customers' accounts. The Company proposed to continue these programs in support of retail access, with modifications to the first and third of these programs described in its direct testimony. (795-801). The changes to the PowerMove program would provide enhanced functionality with ESCOs' obtaining the ability to enroll customers in the program. (796).

Under the POR program, the modifications involve the application of the POR discount to sales tax billed to customers for commodity and the institution of a formal dispute resolution process to be incorporated into the Company's Billing Services Agreement. (797-798; 799-801) In connection with the POR program, the Company is also proposing to modify its electric retail access tariff to conform to its gas tariff with respect to ESCO dispute resolution.[100] A provision will be added to the retail access tariff to assess a charge to an ESCO for failure to settle a dispute in accordance with the dispute resolution procedure. The charge will be equal to the amount disputed by the customer. (800; 321-322).

The Company's continuation of these programs and the changes proposed were not opposed by any party. These programs should be adopted as proposed.

RESA proposes one additional change to the Company's PowerMove program with respect to enrollment and the institution of a collaborative to consider issues related to customer

[100] *See* 2007 Gas Rate Plan Order, Appendix K.

information. CPA proposes that parties other than ESCOs be provided access to the Retail Access Information System ("RAIS"), a Company system developed to facilitate transactions with ESCOs serving electric supply. The Company opposes the program change proposed by RESA, rejects the necessity of the collaborative proposed by RESA, and opposes CPA's proposal to open RAIS to non-ESCOs for the reasons described below.

(i) <u>RESA's Proposal To Expand Existing ESCO Referral Program (Power*Move*) Would Be Costly And Complex</u>

RESA proposes that the Company's existing ESCO referral program be expanded to provide for the enrollment of new customers in Power*Move* at the time the customer initially applies for service. RESA's rationale is that new customers should be provided the same opportunity to take advantage of the ESCO referral program as existing customers. RESA argues that this enhancement of the referral program could be made with a modicum of additional effort and expense. (5179).

The Company disagrees that the enhancement of the referral program would be a simple effort. Such an expansion would require system and process changes that are "not insignificant." (855). The Power*Move* program requires information from and provides information to four of the Company's systems: RAIS; TCIS, the transportation customer information system for gas customers; CUBS, the utility consolidated billing system; and CIS, the Company's customer information system. The proposed change in Power*Move* would require changes in all these systems as well as in the communications system used by ESCOs and utilities to exchange information regarding customer enrollment. While the Company testified that it would be willing to evaluate the technology and funding issues related to making these changes (*id.*) the Company does not presently know if expansion of the program to provide enrollment of new customers is feasible (*i.e.*, whether an automated process can be developed to perform this

function) and, if feasible, how much time the necessary changes would take to implement or how much they would cost to develop. Although RESA did not propose that the Company be provided funding for this work, the Company must be provided a means for recovery of the cost for this program change if it were to go forward with these changes.

(ii) RESA's Proposal For A Collaborative To Consider Providing Customer Data To ESCOs Should Be Rejected

RESA proposes that a collaborative be instituted to examine providing ESCOs with access to customer data, specifically utility customer lists with consumption information by category. RESA purports that this information would empower ESCOs to develop products that meet customers' needs and allow ESCOs to develop marketing plans, properly forecast their potential supply needs, and market to customers. (5181).

The Company disagrees with RESA's recommendation for a collaborative. The Commission is currently examining retail access programs and practices in Case 07-M-0458, Proceeding on Motion to Review Policies and Practices Intended to Foster the Development of Competitive Energy Markets. The Company believes that this issue should and could be addressed in that proceeding (892-893), consistent with the Commission's stated intent in the Notice issued in that case to consider retail access programs and practices issues, including issues raised in utility-specific proceedings and deferred to the generic proceeding, in that generic proceeding. Although the Commission's notice postulated some exceptions to this policy, RESA's proposal does not rise to the level of those exceptions, which would have the Commission act on proposals that would prevent subsidization of competition or would benefit customers without waiting for the generic proceeding to be concluded. (795; 855).

(iii) CPA's Proposal To Provide Non-ESCO Access To The Retail Access Information System Should Be Rejected

CPA witness Dowling argues that Con Edison should provide customers the identical access to RAIS as is now provided only to ESCOs. CPA contends that providing such access would put customers on equal footing with ESCOs when they negotiate for competitive services, which is essential to give customers the confidence to participate in developing markets. (4812-4813).

The Company disagrees with CPA's proposal. First, the Company already provides customers and their consultants upon request the information they are seeking through RAIS. (884). The Company also provides customers information through "My Account" on www.coned.com and on the DMS website, to which access is provided upon request. (856). Second, RAIS is not merely a database of information; as a system, it administers retail access transactions. This system was designed for the Company and ESCOs, acting as trading partners, to support ESCO activities in the competitive marketplace, specifically the enrollment and de-enrollment processes and the exchange of customer cycle usage and billing determinants. Even ESCO access to portions of RAIS is restricted because of Company security concerns that providing anyone with more than this limited access could result in unauthorized changes in Company records.

The concepts of offering Power*Move* to new customers and providing customer lists to ESCOs are not practical to implement as recommended at this time and should be rejected. Information that is requested via RAIS is already being provided, albeit by a different means. Thus, customer access to that system should not be required. The Company's proposed changes to its retail access program reflect reasonable enhancements and should be approved.

h) Miscellaneous

The Company proposed four other customer operations programs that were not opposed by any party: system development with respect to changes to the Company's customer service systems; the dedication of additional resources to storm response as part of the Company's storm mobilization activities; updated service fees for inspecting tampered apparatus; and bill redesign. (784-789; 790-792; 794). These programs should be approved.

3. Electric Production

The Company proposed a number of O&M program changes to its electric production category, increasing projected spending in these areas by approximately $7 million. (907-935). Some of these program changes included additional spending for facilities maintenance, gas turbines and preventative maintenance. *(id*., Exh. 55). Staff made one adjustment to the costs of these programs, proposing to reduce water costs by $35,000. While the Company did not object to this adjustment since the costs were inadvertently escalated twice, once through general escalation as well as again by the Electric Production Panel, the Company would note that since its rebuttal testimony was filed, the City has announced yet another double-digit increase in water rates. This increase will affect the rate year cost for water, and is above the level of the cost included in the inflation pool. In fact, it is closer to the level the Company's initial request.

On the other hand, CPB made three adjustments totaling $5.9 million, eliminating nearly all of the electric production O&M program changes. CPB adjusted the categories of facilities maintenance, preventative and corrective maintenance and gas turbine maintenance, claiming that insufficient and unreliable information was provided, that maintenance was deferred in anticipation of a rate case, and that certain categories should be considered capital, not expense. (3275-3279). CPB's adjustments should be rejected.

CPB argues that the program change for gas turbine maintenance should be removed from the revenue requirement because (1) the program does not have any associated capital costs; (2) actual spending has been below the requested amount in recent years; and (3) this program is capital in nature.

In rebuttal, the Electric Production Panel explained that the gas turbines are needed for system reliability as support for peak summer demand as well as part of a blackout restoration plan (943-944); that the level of expenditures for gas turbine maintenance has been increasing over the past several years (943-956); and that the Company has been doing maintenance on these gas turbines for the past several years, focusing on upgrading the control system so that the units can start reliably. (960-961). Much of the work was capital as they were upgrades to the control system. (961). The next phase of the programmatic work is to enable the gas turbines to operate at the nameplate rating (17 MW as opposed to the 13 MW at which it currently operates) for the remaining life of the units. (957-958; 960-961). The proposed expenditures are necessary for these units to operate when they are needed at higher levels.

CPB's claim that this work should be capitalized is incorrect. The work is for various activities, including, but not limited to removal and replacement of the engines, and inspection and repair of electric generator rotors and associated equipment, all of which are considered O&M, as explained in the Company's response to CPB 6, included in Exhibit 215. As explained above, the Company follows the accounting rules for capital versus expense as required by the FERC.[101]

[101] For a recent case discussing FERC's capital versus expense policy on matters like this which demonstrates FERC considers work to be capital as a "substantial addition," if it extends the "useful life, operating capacity or efficiency" of the equipment, *See*, Northern Natural Gas Company, Docket AC07-129-001, Order on Rehearing, 121 FERC ¶61,002, October 1, 2007. The maintenance of the gas turbines is simply to return the unit to its normal operating life, not extend it. *Northern Natural Gas* is also instructive as to the dollar values included, concluding that the large cost of a project does not necessarily mean it is capital.

For the reasons explained in this section, as well as the T&D section dealing with this issue, the gas turbine project is not capital, as it is not designed to extend the useful life of the equipment. (958, 960; 962-966).

The remaining adjustments made by CPB to the Electric Production expenses should be similarly rejected. For preventative and corrective maintenance, CPB combines these two categories, which (when combined) had over $5 million in expenditures in the historic year. The Company requested a $1.17 million program change above the existing level of expenditures in the preventative maintenance category. CPB adjusts the spending based on a calculation of a three-year average for both categories in total, claiming that maintenance may have been deferred. (3278-3279, Exh. 214; Exh. 55). In addition to providing no justification or basis for its proposed adjustment, CPB's proposal would yield an anomalous result. Specifically, CPB's proposed use of a three-year average lowers the spending below the level of expenditures the Company made in total in the historic year for these two categories. The Company explained the need for all of these programs in the Electric Production Panel's testimony. Preventative Maintenance is the scheduled inspection and repair of equipment that impacts unit availability. (921). In discovery and rebuttal, the Company explained that the corrective maintenance categories of expenditures remained flat in the rate year and that this work was needed to support

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Additionally, *Northern* is mistaken that cost is a principal factor in determining whether *Northern's* expenses for leak clamps should be capitalized or expensed as maintenance under the Commission's accounting rules. While cost is one factor to consider in determining whether to capitalize or expense an item, it is the nature and purpose of work performed which governs the classification of costs under the USofA.

Further, as the June 18 Order correctly points out, the fact that installing the leak clamps is an expensive maintenance procedure does not alter the fact that it is maintenance. For example, in the *So. Cal Edison* proceeding, the Commission found that $58 million of sleeving (pipe/tube modification) costs could not be capitalized as plant in service … [as the] work did not meet the criteria for capitalization as a substantial addition….(¶¶23, 24)

the reliability of station equipment. (947-948). CPB's three year averaging approach is not supported by the historic year's level of expenditures and should be rejected.

Regarding CPB's proposed facility maintenance adjustment (3778), the Electric Production Panel explained why is necessary to paint stacks and remove structural deficiencies (946). The Panel explained that the "integrity and reliability of station operating equipment and the safety of employees and the public are compromised by the deterioration of steel, concrete and other building structure components." *(id.)* They also noted that some of these repairs were postponed until the completion of East River 1 and 2 so as not to impede the start up of those units. (946), which explains the lower historical level of spending.

Viewed from these perspectives, CPB has demonstrated no basis for any Electric Production adjustments and consequently they should all be rejected.

4. <u>Emergency Preparedness Programs</u>

The Company's Electric Emergency Preparedness Panel proposes four programs (976) designed to improve the Company's ability to mobilize its emergency response organizations, dedicate additional planning resources, provide for consolidated command and control, replace vulnerable equipment to mitigate potential equipment failure during coastal storms, and provide resources to better understand the scope of an events. (974). Each of these programs is consistent with the Company's established emergency planning and response principles, *i.e.*, 1) designing programs and systems to reduce the probability of an outage occurring; 2) designing systems and processes to minimize the duration of an outage when an incident occurs; and 3) designing and implementing timely and responsive communication strategies for all internal and external stakeholders. (975). The O&M costs for these programs are projected to total $3.976

million in the rate year and capital expenditures are estimated at $8.4 million for each of 2008 and 2009, and $6.4 million for 2010. (Exh. 58).

a) <u>Staff Adjustment</u>

Staff proposes to eliminate the total funding -- both capital and O&M -- proposed by the Company for these emergency planning and response programs. (4196-4197). Staff's sole basis for recommending the total elimination of funding for these programs is its contention that the Company lacks "an overall, comprehensive, emergency planning structure." (4195). Staff states that "a clear structure for emergency preparedness needs to be established before the Company moves forward with these programs." (4196). Staff concedes that the Company's funding request and any incremental costs associated with the comprehensive plan should be considered in this proceeding for inclusion in rates. (4198).

Staff does not specifically criticize any of the proposed programs on their merits. Indeed, Staff concedes that the programs proposed by the Company "are intended to improve the Company's storm and heat event readiness, protect equipment from coastal storm surges, better respond to customer outages, facilitate effective restoration, and improve on internal and external communications." (4190).

As discussed below, the evidence in the record demonstrates the need for the proposed programs regardless of the Company's organizational structure for emergency planning. (1005-1006). Moreover, Staff itself asserts that the Company needs to take steps to improve its emergency preparedness (4194; 4197-4198) and anticipates that incremental funding will be required to implement the comprehensive emergency preparedness plan Staff expects the Company to implement. (4196).

Accordingly, Staff's position regarding the complete elimination of the Company's requested funding for emergency preparedness is inconsistent with Staff's arguments that the Company needs to make improvements in this area, that the Company should be reimbursed for the incremental costs of such improvements, and that such a determination be made in a manner that provides for such costs to be reflected in the rates established in this proceeding. (4194-4196).

As discussed below, the procedures suggested by Staff witness Eng to establish such programs and then provide for funding in rates appear neither reasonable nor practical. As such, the Commission should not eliminate the proposed funding for these activities from the revenue requirement and thereby create the probability that rates established in this proceeding will not provide any funding for activities that both Staff and the Company contemplate will be implemented during the rate year. Should the Commission reject the Company's proposed programs, the funds provided in rates would necessarily be applied to the activities that the Company ultimately undertakes, whether pursuant to Commission direction in this proceeding or the initiatives undertaken by the Company as a result of the audit proceeding. In fact, the rate determination should allow for the Company to defer any incremental costs, above the amounts provided in rates, associated with actions that the Company undertakes pursuant to and consistent with the audit proceeding or as directed by the Commission.

b) <u>Emergency Preparedness Programs</u>

Staff's contention regarding the Company's organizational structure for emergency preparedness provides no justification for completely eliminating funding for the Company's emergency preparedness programs. The Company's organizational structure for emergency preparedness has no impact on the need for these programs. To illustrate this point, under the

Company's proposed Coastal Storm Mitigation program, each Electric Operating region has evaluated the need for transformer vault replacements with flood-resistant submersible transformers, and flood-disconnect switch installations to reduce the number of customers potentially impacted and the duration of customer outages during a coastal storm that results in significant storm surge. (1008-1009). Staff recognizes that more than half of the funding the Company requests for emergency preparedness is attributable to the Coastal Storm Mitigation program. (4203). Staff does not dispute that the purpose of this program is to identify potentially vulnerable facilities and address physical infrastructure installations. (4193-4194).

Even if, assuming *arguendo*, Staff's contention regarding the Company's organizational structure were true, it would have no bearing on the need for programs such as Coastal Storm Mitigation. Neither the vulnerability of identified facilities nor the proposed infrastructure installations are dependent on the organizational structure the Company employs to address emergency preparedness. Similarly, the Company's proposal to build an Incident Command Center ("ICC") and the introduction of a Control Center Screening Group (utilized to manage the appropriate resources to respond to events) are independent of the organizational structure utilized by the Company. (1007-1008). Thus, the Company should not be required to submit a comprehensive emergency preparedness plan as a pre-condition to including the funding for these programs in the current rate proceeding.

Furthermore, there is nothing in the Independent Electric Emergency Audit Report[102] suggesting how the Company should implement programs such as the Coastal Storm Mitigation,

[102] Case No. 06-M-1078, *Proceeding on Motion of the Commission to Audit the Performance of Consolidated Edison Company of New York, Inc. in Response to Outage Emergencies*, Final Audit Report (issued October 24, 2007) ("Audit Report"). While the Audit Report identifies opportunities for improvement, it also identifies many areas where the Company is performing at or above industry standards. The Company has committed to working cooperatively with Staff to review the Audit Report's recommendations with the goal of continuing to improve the Company's emergency planning and response.

the development of an ICC or the establishment of a Control Center Screening Group. The audit -- conducted pursuant to Commission order in a separate proceeding -- examined the Company's emergency planning and preparedness.[103] Prior to the issuance of the Audit Report, Staff suggested that the Company consider the Audit Report's findings and recommendations before implementing its proposed programs. (4196). In rebuttal, the Company argued that there was no basis for concluding that the audit findings would indicate that any of the programs would not be necessary or would require material revision. (1009-1010). The Company's arguments have largely been borne out by the final Audit Report, which makes no findings or recommendations related to the Company's Coastal Storm Mitigation program, an ICC or the Control Center Screening Group.[104] This should come as no surprise since, as explained above, the need for such programs is unrelated to the Company's organizational structure for emergency planning.

As noted below, the Company has committed to finalizing its master strategy by March 2008, after which the expansion of the group will be absolutely necessary to meet the goals and objectives set forth by this strategy.

c) <u>Staff Proposal for Emergency Preparedness Plan</u>

Staff's recommendation regarding the submission of a comprehensive emergency preparedness plan is inconsistent with the Commission's anticipated actions in the current rate proceeding. Staff recommends that the Company prepare a comprehensive emergency preparedness plan taking into account the findings and recommendations of the management audit. (4196). Staff concedes that it does not anticipate the Commission will issue any orders in this proceeding prior to January 1, 2008. (4199). Nevertheless, Staff recommends that the Company file a comprehensive plan with the Commission no later than January 1, 2008, to

[103] (*Id.*)
[104] (*Id.*)

address incremental costs in the emergency preparedness area. (4196). Because the Commission will not likely act in the current proceeding to assess and render a decision on either Staff's or the Company's proposals before January 1, 2008, Staff's recommendation that the Company file its comprehensive plan by January 1, 2008 will likely be a moot issue.

Staff's recommendation regarding the submission of a comprehensive emergency preparedness plan is also unreasonable and Staff should defer to the schedule the Commission ultimately adopts in the separate audit proceeding.[105] Staff's recommendation fails to take into account the Commission's notice dated October 25, 2007 in Case No. 06-M-1078. (4199-4200). In that notice, the Commission gave the Company until November 6, 2007 to submit comments on the audit report; other interested parties until November 20, 2007 to file comments; and all parties until December 3, 2007, to submit reply comments. Accordingly, before adopting the Audit Report and directing the Company to implement any recommendations, the Commission will need to have an opportunity to consider the comments from the Company and any other interested parties. Therefore, it would appear that the earliest opportunity the Commission would have to act on the Audit Report would be at its December 12, 2007 Open Session.

Although the Company has already begun working to develop a comprehensive emergency preparedness plan based on the issues identified in the Audit Report, much work remains to be done. On November 6, 2007, the Company submitted comments in the audit proceeding in which the Company committed to providing a comprehensive plan by March 2008 and an interim progress report by January 15, 2008.[106] Staff's recommendation to submit a plan by January 1, 2008 gives the Company less than three weeks after the Commission's expected

[105] The Company would note that Staff did indicate some flexibility and conceded that it would be willing to reconsider its position based upon the actual schedule the Commission adopts in the audit proceeding. (4202).
[106] Id., Notice Inviting Comments (issued October 25, 2007). The Company's comments can be found at the following NYPSC link: http://www.dps.state.ny.us/06M1078_ConEdisonCommentsonAuditReport.pdf.

order to complete the development of a comprehensive emergency preparedness plan, including incremental costs associated with any programs proposed under the Company's comprehensive plan. (4201-4202).

Although Staff properly proposes that the costs of these programs be considered in this proceeding for inclusion in rates (4198), its impractical procedural approach denies the Company a reasonable opportunity to do so. Accordingly, consistent with Staff's recognition of the need for additional Company efforts in the area of emergency preparedness, and no evidence that the Company's forecast of these costs is not reasonable, the Company's proposed revenue requirement should not be adjusted to eliminate the Company's forecast of these costs.

5. <u>Interference</u>

When New York City or any other municipality in the Company's service territory performs work such as installing or repairing water mains, sewers and drainage facilities, or reconstructing roadways, curbs, and sidewalks and if the work affects Company electric facilities, Con Edison must bear the costs to support and protect its facilities. (1171).

The Company's initial forecasted amount of O&M interference costs for the rate year was $81 million, excluding Company labor. (1172). The methodology used to calculate the rate year forecast is based on New York City's Capital Commitment plan, which is generally published in January, April, and September of each calendar year. (1178-1180).

Under the Lower Manhattan reconstruction program that resulted from the World Trade Center ("WTC") incident, the Company has spent approximately $67.5 million for Electric O&M from 2002 to 2006 for interference work in that area. (1172). Due to the existence of federal and other potential sources of reimbursement, the Company created a special account for this work so that these costs can be accumulated and submitted for reimbursement *(id.)* The

provision for reimbursement from federal funds expires on December 31, 2007 *(id.)* Therefore, the Company proposes that expenditures for the Lower Manhattan projects be recovered through rates in the same manner as other interference expenditures. (1172-1173). The forecast for WTC Interference O&M expenditure for the rate year is approximately $18 million. (1173).

The Company incorporated several corrections Staff identified during the course of discovery and included reflected these corrections both in the Company's preliminary update in August, as well as in the Company's formal September 28, 2007 update. These corrections (1) decreased the four-year average of the ratio of New York City capital commitment targets to the actual expenditures from 100.7 percent to 98.3 percent for the 2003-2006 period; (2) decreased the four-year average of the ratio of New York City capital expenditures to the Company's interference expenditures from 11.7 percent to 11.6 percent; and (3) removed the escalation factor added by the Company's Accounting Panel, since the rate year numbers were based upon forecasted expenditures. (1191-1192; 3587-3589).[107]

a) <u>Staff Adjustments</u>

Staff proposes two adjustments. The first adjustment includes an escalation on the labor component of the interference expense resulting in an increase in the interference expense of $148,638. (1194; 3591-3592). The Company accepts this adjustment.

Staff's second adjustment proposes using the average New York City commitment target ratio for the month of September in the last four years rather than using the latest Capital Commitment Plan issued by the City. (1194-1195; 3590-3591). As noted above, the City issues a Capital Commitment Plan three times a year. The Company historically has used the latest Capital Commitment Plan issued by the City as a component in forecasting interference

[107] These corrections also address CPB's proposed adjustment disputing the application of the escalation factor to interference costs (3284-3285), thereby rendering CPB's interference escalation adjustment moot.

expenses. (1180-1181). Staff justifies using an average of the September results for the years 2003 to 2006 based upon the wide variations seen in target ratios in any given calendar year. (3590-3591). Based on a 2003 to 2006 average of the September ratios, Staff altered the commitment percentage from 89.3 percent to 65 percent. (3590-3591). This results in a reduction of interference expenditures of $11.7 million. (1195).

Because the Company viewed this adjustment as being generally consistent with the 66 percent ratio in the latest NYC Capital Commitment plan (*i.e.*, September 2007), the Company agreed to Staff's adjustment. However, the Company does not agree with Staff's methodology and would note that Staff provided no basis for using historical ratios or for using historical ratios only from a particular month. The Company is not in a position to speculate on what target ratios the City will employ and the only information that the Company can reasonably rely upon is the latest target ratio issued by the City. Moreover, the variability in the target ratios identified by Staff in support of this adjustment provides justification for continuing to apply a bilateral true-up mechanism to interference costs (discussed in section VII of this Brief). The commitment target ratio is a necessary component of the Company's interference forecast that is outside of the Company's direct control. (1186-1187; 1198-1199).

Based upon the corrections described above, but before applying the two adjustments, Staff calculates the total forecasted rate year expenditures, including Lower Manhattan, to be $103.656 million. (3589). This is incorrect. Relying on the same corrections, the Company calculates the total forecasted rate year expenditures, including Lower Manhattan, to be $104.98 million. (1196). It appears that the discrepancy arises from Staff's use of historic year interference labor -- $2.326 million -- instead of forecasted rate year labor -- $3.741 million (1196). After the two adjustments described above are applied, the Company's interference

expenses are reduced by $11.6 million. (1194-1196; 3585). This results in total rate year interference expenses of $93 million.

b) <u>CPB Adjustment</u>

CPB proposes an adjustment that would reduce the Company's interference expenses by approximately $27 million. (3281). For the reasons discussed below, CPB's $27 million adjustment should be rejected.

CPB arrives at its figure by applying a ratio of the budgeted expenditures for 2006 compared to actual 2006 expenditures (74.2 percent) to the Company's rate year forecast. (1203, 3281). The budget to actual ratio for 2006 is an outlier compared to the ratios from 2002 to 2005. (Exh. 74). Accordingly, there is no reasonable basis for assuming that the one-year deviation in 2006 will continue in the rate year.

Moreover, CPB mischaracterizes the Company's proposed adjustment, claiming that the Company is seeking a 97 percent increase in interference expenses for the rate year. (3280). CPB erroneously compares an historic figure that does not include Lower Manhattan interference expenses with a forecast that includes Lower Manhattan expenses. (1201-1202). As explained by Company witness Gencarelli, in the past, Lower Manhattan interference expenses have been treated separately from other Company interference expenses due to the potential for recovery of these expenses from federal funds. (1182-1186; 1202). As this federal recovery program is expiring December 31, 2007, the Company's forecast for the rate year reflects the fact that, going forward, the Company will no longer separately account for Lower Manhattan interference costs but will include these expenses with all other interference costs. (1186).

And as explained in the Company's initial testimony, the variance between the historic year and the rate year is attributable to an anticipated substantial increase in City infrastructure activity during the rate year and the fact that the City's actual expenditure for the historic year was significantly lower than anticipated. (1177). As noted in the Company's rebuttal testimony, the Company works closely with the City during the planning phase of City infrastructure improvement projects. (1198). Based upon these ongoing discussions with the City, the Company has no reasonable basis at this time for concluding that the City will underspend in the rate year.

CPB's 97 percent calculation also does not account for the reduction in forecasted expenses resulting from the Company's acceptance of Staff's adjustments. Because the Company accepted these adjustments after CPB filed its direct testimony, CPB would not have been aware of this reduction when it made its claim. As discussed above, these adjustments result in an $11.6 million reduction in forecasted interference costs.

CPB expresses concern with the Company's estimates of the City's costs. (3280). Once again, CPB relies on an erroneous comparison to support its claim. According to CPB, the "request of $106.433 million for the rate year is significantly higher than the five year average cost of $60.325 million." (3280) First, before applying Staff's adjustments, the Company's total interference rate year forecast, including labor and Lower Manhattan expenses, was $104.980 million, not $106.433 million. (1196). Second, the $60.325 million five-year average does not include the Lower Manhattan expenses incurred over those five years. (1210). As discussed above, these expenses had been treated separately but in the future will be included in overall interference expenses.

CPB also expresses concern with the Company's estimates of the number of projects the City is expected to complete. (3280). As CPB concedes, the Company has little control over the scheduling of interference work or in determining which projects are or are not undertaken (3340).[108] The Company necessarily relies upon the commitment target information that is provided by the City. (1178-1179). As noted above, in this case, the Company agreed to Staff's adjustment to a 65 percent target ratio because this adjustment was consistent with the latest available target ratio.

Nor should CPB's claims that the Company did not adequately respond to its data requests serve as a basis to support CPB's proposed adjustment. Although CPB expresses dissatisfaction with the Company's responses to CPB data requests related to interference costs (3280-3281), CPB stipulated on the record that it did not make any motions to compel the Company to provide additional information, or otherwise seek relief from the presiding judges in this proceeding. (3335-3336). Consequently, the Company reasonably assumed that the information it provided was responsive to CPB's data requests.

For all of the foregoing reasons, CPB's adjustment to interference expenses should be rejected.

6. <u>Environmental – MGP/Remediation</u>

Randolph S. Price, the Company's Vice President for Environment, Health and Safety ("EH&S"), testified regarding the Company's remediation program,[109] the objective of which is to perform properly the required remedial response measures (investigations followed by any necessary remediation) at sites that have been contaminated by past releases of petroleum

[108] In that regard, it bears mention that CPB did not oppose the Company's proposed reconciliation mechanism for interference expenses.

[109] Mr. Price also proposed a number of other program changes, including normalizations, that were all unopposed and should be adopted.

products, hazardous wastes and hazardous substances from the Company's and its predecessors' facilities and operations. The program encompasses four categories of sites: 1) former Manufactured Gas Plant ("MGP") sites; 2) Superfund sites; 3) Appendix B sites; and 4) the Astoria Site. (458-459). No party questioned the need for the program, which is consistent with both federal and state policy of investigating and remediating sites contaminated with hazardous substances or petroleum.

With respect to the MGP sites, Mr. Price provided background information concerning the MGP site investigation and remediation program, a list of the 50 MGP sites addressed under this program,[110] the current status of the program, and the specific investigation and remediation activities that are expected to be conducted during the rate year. As explained by Mr. Price, the Company's execution of an agreement with the New York State Department of Environmental Conservation ("DEC") in 2002, required the Company to investigate and, if necessary, to remediate 45 of the Company's MGP sites, began a period of significant increased activity for this program. (459-470; Exh. 18.)

Mr. Price also discussed the Company's anticipated investigation and remediation activities during the rate year for its Superfund sites. These are: 1) third party sites to which Con Edison has shipped hazardous substances for treatment, storage and disposal and has formally been designated as a potentially responsible party for investigation and remediation by a government environmental agency; 2) sites that were formerly owned by Con Edison and for which current site owners assert claims against Con Edison for investigation and remediation; and 3) sites currently owned by Con Edison at which Con Edison is required to conduct cleanup

[110] In his update testimony, Mr. Price noted that one other MGP site was added to the Company's agreement with the DEC. (523).

work because of releases of oil, dielectric fluid, PCBs, or other hazardous substances from its equipment, facilities, or operations. (470-480).

Appendix B of the Company's 1994 Consent Order with the DEC, as amended by the 2006 Consolidated Consent Order, addresses spills and leaks of petroleum products from the Company's fuel oil storage tanks, No. 6 fuel oil pipeline system, high-pressure pipe-type electric feeders, and other types of oil-filled equipment, and requires Con Edison to complete an investigation and remediation process at such sites. There are 48 open sites that are being addressed pursuant to Appendix B. (480-484; Exh. 19).

Portions of the Astoria Site are being investigated and, if necessary, remediated pursuant to the requirements of the Company's hazardous waste permit for its PCB Waste Storage Facility at Astoria. Mr. Price discussed the activities anticipated at this site during the rate year. (484-486).

Mr. Price then described the Company's process for estimating the costs of the Company's remediation program and the steps the Company has taken and is taking to minimize the costs of this program. For the 12-month period immediately prior to the rate year, the total expenditure for this program is projected to be $55.6 million. The projected expenditure for the rate year is $115.3 million; for both the second and third rate years, it is $42.5 million. (486-495; 517-523; Exh. 21).

Adjustments to these projections were proposed by Staff and CPB. Staff proposed four adjustments to the linking period and the rate year. (3593-3597). The Company accepted all of these adjustments as part of its update presentation. (524-525; Exh. 95, Schedule 2, page 1, line 30).

CPB, while claiming to support the cleanup of MGP sites (3313), nevertheless proposed the disallowance of remediation costs in this case, contending that the Company did not provide cost support for this program when requested. (3229-3233). CPB's contention is in error. Its position is based on a misdirected interrogatory, and it should be rejected. Contrary to CPB's contention, the Company provided extensive cost support for its remediation program.

CPB propounded an interrogatory regarding remediation costs in early July. The interrogatory was directed specifically to the Company's accounting panel in that it stated "Refer to page 41 of the Accounting Panel's testimony". (Exh. 23). The Company responded to this interrogatory. Although the CPB now asserts that the Company's response was nothing more than "some numbers on a page" (3230), it never followed up on its original request. Notably, CPB never addressed an interrogatory to Mr. Price, the witness who presented the Company's remediation program and testified as to its costs.

Despite the CPB's discovery errors, it was, in fact provided extensive backup information regarding the costs of the Company's remediation program. Staff directed several interrogatories to Mr. Price requesting supporting data for various historic periods and the rate year. Such supporting data were provided to Staff, and copies were sent to CPB. (526; Exh. 22). In sum, CPB's contention is clearly without merit and it should be rejected.

7. <u>R&D Spending</u>

Company witness Arthur Kressner, Director of Electric Power Supply Research and Development, explained the need to increase the Company's R&D spending by $11 million for various R&D programs. (122-150; Exh. 4). These R&D programs include projects related to network reliability, stray voltage, fault locating and energy efficiency. (*id.*) Staff witness Pause agreed that all the projects were necessary and should be undertaken but provided a slippage

adjustment of approximately $3.75 million. (4181). In rebuttal, Mr. Kressner explained that while in some years it may appear that the Company's spending was below budget, actual expenditures were, in some cases, reduced by credits that the R&D budget received as a result of the capitalization of successful R&D projects. (147). That is, if a project is successful, the development and demonstration funds previously expended by R&D are charged to capital and credited to R&D expenses, generally in subsequent years. (147-148). The crediting process is unpredictable. (148). Mr. Kressner noted that adding the credits back in would bring the spending in 2005 and 2006 closer to the actual R&D budget. (148).

Mr. Pause testified that all the programs are warranted and justified (4181-4182; 4184), but provided no guidance on which projects should be undertaken if his slippage adjustment were accepted. (148). As such, Mr. Kressner proposed the implementation of a true-up mechanism, where the full amount of the funding proposed by the Company is included in rates, subject to a downward annual reconciliation if the actual amounts spent for R&D are less than the amount included in rates. (149). Mr. Pause agreed with the proposal. (4184-4185). As such, the level of spending proposed by Mr. Kressner should be included in rates, subject to a downward reconciliation if the full amounts are not spent.

8. <u>Facilities Spending</u>

Company witness Carol Monti-Barris, Vice President of Facilities, explained the need for the Company to undertake nearly 300 projects over the next four years to upgrade the facilities within its service territory and to plan for meeting its future organizational needs. (1052). CPB complains that the Company did not provide adequate documentation for the costs of these projects and recommends three adjustments to the Company's projected expenses. (3265-3268). Two of these adjustments relate to CPB's recommended disallowance of certain project costs

and its alternative proposal to treat these costs as capital rather than O&M if the costs are deemed reasonable. (3267-3268). The third of these adjustments is confusing but could be read to require deferral of the costs of the Company's Master Plan for determining the facilities needed to accommodate the changes occurring, and expected to occur, in the Company over the next four years. (3268). CPB's adjustments are without a rational basis and should be rejected.

a) <u>Project Expenses</u>

The Company strongly disagrees with CPB's characterization of the documentation provided by the Company in support of the costs for its facilities projects. As Ms. Monti-Barris explained, the Company received and responded to the two interrogatories CPB propounded regarding these projects, and its responses were fully responsive to the questions, including cross-referencing, providing supporting documentation for the programs' historic, current, and forecast costs, and responding to CPB's requests for clarification. (1098). As has been previously pointed out, CPB never complained about the responses provided by the Company during the discovery phase of this proceeding and its unfounded criticisms of the Company's presentation, also addressed by the Company's Accounting Panel (1389-1390), should be disregarded.

b) <u>Local Law 26</u>

Consistent with its overall approach to the Company's filing, CPB recommends the disallowance of the electric portion of the costs attributable to a Building Service project listed under "Associated O&M Costs – Capital Projects" on Exhibit 61, asserting that the Company did not provide "sufficient detail" to support the costs, and that these costs be capitalized if the Commission were to deem the costs reasonable. (3267).

As Ms. Monti-Barris explained, these expenses are associated with a critical project, compliance with New York City's Local Law 26 ("LL26"), which requires, by July 1, 2019, the full sprinklering of all office buildings 100 feet or more in height. (1056). For Con Edison, the law is applicable to its corporate headquarters at 4 Irving Place. At this point, office renovation and sprinklering have been mostly completed on four floors of 4 Irving Place, leaving 24 unrenovated or partially renovated floors and eight tower stages. (1059).

The Company will have to implement an aggressive renovation schedule and renovate on average approximately one and one-half floors each year to meet the 2019 deadline. (1059). This aggressive schedule is complicated by the fact that employees must be relocated from their work areas during renovations since, due to the often required abatement of environmentally sensitive materials (*e.g.*, asbestos), it would be neither safe nor practical to perform renovations only during their off-shifts. (1058). And, since there is insufficient space at 4 Irving Place and other Company facilities for housing these relocated employees, the Company needs to reassign certain of these employees out of the building to non-Company locations during the renovation process. (1059). The O&M expenses associated with the temporary relocation of personnel include the costs of renting off-site office space, site preparation, and the physical moving of personnel. (1060; 1090-1091).

CPB asserts that the Company provided insufficient documentation for this project and that, if the costs were "better explained, we would be inclined to treat them as capital costs." (3267). Ms. Monti-Barris fully explained this project in both her direct (1055-1061) and rebuttal testimony. (1089-1093).

As to CPB's proposed treatment of these costs as capital expenditures, as explained above, the Company must implement, on a consistent basis, its capital vs. expense procedures,

which comport with the accounting instructions promulgated by the Commission and FERC. (1092).

Contrary to CPB's unexplained "inclination," the relocation costs associated with the LL26 compliance project should not be considered capital. Consistent with its accounting instructions, relocation costs have been historically ruled O&M by the Company's Property Records Accounting Section, and renovations to a temporary site, leased but not owned by the Company, are considered O&M since there is no addition or betterment to the original construction of a Company asset. (1092). Thus, since the space leased for employee relocation is temporary in nature, to be used only in connection with the renovation of Company property, and not intended for long term or permanent use by the Company in lieu of Company office space, it would be improper under the Company's accounting guidelines to treat these expenditures in the same manner as improvements to Company property. (1093).

c) <u>Building Infrastructure Restoration</u>

The Company's plans for Building Infrastructure Restoration include several projects for restoring equipment and systems that are approaching their generally accepted life expectancies and require upgrading for continual operation. (1073). According to CPB, the Company's projected costs for these Building Infrastructure Restoration projects should be reduced since the projected increase from historic costs for this category of projects is "excessive" and, "arguably, that expense *could* also be capitalized." (3267-3268). CPB recommends reducing the Company's projected increase of $5.36 million for these projects to $4.403 million ($3.573 million for electric operations) and deferring and amortizing this reduced amount since these "renovation costs do provide a benefit to future periods and appropriately should be charged to those future periods." (3266).

Ms. Monti-Barris explained why CPB's proposals are incorrect. First, the projected O&M expenses for Building Infrastructure Restoration, consisting of approximately 15 projects, are not overstated. The increase in Building Infrastructure Restoration costs is primarily driven by two projects; (1) compliance with Local Law 11 ("LL11"), which requires the periodic inspection of the exterior facades of buildings in New York City greater than six stories in height; and (2) restoration of cooling tower components and relocating associated structural steel and piping on the roof of 4 Irving Place. (1094). Both of these projects are critical to public and employee safety and are therefore, necessary expenses. (1095-1096).

LL11 is intended as a safety measure to protect the public from falling building materials and to improve awareness of the importance of maintaining and restoring architecture in the City. (1062; 1095). Ms. Monti-Barris explained that the Company's recently completed report on inspections conducted in 2006 identified certain repairs that must be completed within five years and prior to the next inspection required under LL11. (1062-63). These include repairs to parts of the building's façade and the recommended replacement of caulking on all of the building's windows. (1063). Due to the presence of asbestos-containing material in the window caulking, special complex procedures, including internal plasticizing and air monitoring, are required to remove the existing window caulking. It is expected that the complexity of the procedure and associated repairs required by LL11 will take a period of four years, with one building façade being repaired per year, at an annual cost of approximately $1 million per year. (1064-1065).

Cooling Tower restorations are repairs that mitigate the risk of the building occupants suffering from airborne diseases, such as Legionnaires Disease. Since the Cooling Towers are located on the roof of the building, the project is intended to protect the public from the potential

of broken debris falling from the equipment. (1095-1096). CPB's suggestion that the costs of projects critical for public safety should be reduced simply because these two projects result in costs for the category of Building Infrastructure Restoration projects exceeding historic amounts should be rejected. Ms. Monti-Barris fully explained the nature of the work to be performed in the rate year. (1062-1065; 1094-1096).

Second, contrary to CPB's assertion, the fact that these projects will provide a benefit to future periods is not a basis for capitalizing these costs. O&M programs routinely provide benefits to future periods. (1094). Consistent with its accounting instructions, projects of this nature, including LL11 and Cooling Tower casing/restorations, have historically been ruled O&M by the Company's Property Records Accounting Section. (1094). Following the established FERC and Commission rules, the basis for the Company's "expense" ruling has generally been that LL11 requires "repairs" to sporadic areas of the buildings rather than complete replacement of external walls or parapets on the buildings. (1094-1095). Similarly, with respect to the Cooling Towers, components of the equipment are being repaired and/or replaced rather than replacing the entire unit. (1095).

CPB has provided no basis for the Commission to either reject the Company's capitalization policy or for the Company to deviate from this accounting treatment for the Company's Building Infrastructure Restoration expenses.

d) <u>Master Plan Study</u>

The Master Plan Study is a Company-wide strategic plan that is designed to examine all of the Company's facilities, employees, and organizational functions to determine the facilities needed to accommodate the changes occurring, and expected to occur, in the Company over the next four years. (1073-1074). CPB makes an unclear and inconsistent recommendation,

suggesting that the costs of the Master Plan Study "be deferred until the cost is actually known and measurable and it can be established that there was a benefit to ratepayers from the study." (3268). If CPB is suggesting that the Company undertake the study and make the recovery of these costs subject to an after-the-fact determination that there is a benefit to customers, the recommendation is patently unreasonable. (1096). If CPB is suggesting that the Master Plan Study itself be deferred, there will be nothing to evaluate. (1096).

Ms. Monti-Barris explained the need for the Master Plan and associated study. (1073-1074; 1096-1097). At this point, several Company organizations are outgrowing their current locations and a number of Company building leases are due to expire within the next five years. (1073). In addition, the Company has demonstrated that it will ramp up staffing levels commensurate with the increased level of electric infrastructure improvements. (1096-1097). The large numbers of new employees necessitate that the Company undertake a full scale study and analysis of all the Company's facilities (approximately 25 major sites), employees, and organizational functions. (1097). A Master Plan needs to be developed to accommodate these changes, as well as any possible future changes, in an effort to optimize the usage of the Company's existing and new facilities. (1097). Customers will benefit from a financial and customer service standpoint. For example, maximizing usage of an existing building may result in avoiding the construction of new office or work-out locations, which would avoid not only the cost of building new facilities but also the cost of maintaining them. (1097). In addition, re-aligning organizational locations based on their respective duties will enhance the Company's response to customer needs. (1097).

The Company is presently moving forward with this project. A team has been established to ascertain the total number of affected facilities and their respective basic

information. (1097). The team's objective is to issue an RFP late this year to employ the services of a consultant during the second quarter of 2008. (1097).[111] The Company's estimate of the costs is based on extrapolating the costs of a past similar study conducted on a Company facility and presents a reasonable expectation of the costs of the planned Master Plan Study. (1098). Whatever CPB's proposal is for the Master Plan, it should be rejected.

9. <u>Public Awareness and Energy Information Programs</u>

The Company's Accounting Panel explained why Public Affairs requires approximately $8.5 million (of which Electric's share would be approximately $7 million) to address various issues, including expanding public awareness and energy information programs, undertaking website upgrades and printing/producing publications.

As detailed in Exhibit 106, the Company intends to undertake two informational advertising programs – "Energy Education" and "Working For You" during the rate year, which primarily drive the $7 million program change. The Company explained it intended to "inform our customers and the public about topics such as the need to maintain and enhance the electric infrastructure, energy conservation, and how to report power problems and otherwise contact the Company in the event of an emergency, as well as about certain Company programs such as our Minority and Women Owned Business program." (1306). The Company explained that the purpose for expanding these programs was to continue to educate and inform customers about Con Edison's infrastructure investments and advise the public about how to contact Con Edison to report any power problems, safety concerns or emergencies. The Company emphasized the importance of providing information to the public in the event of a service outage or other emergency. (1417).

[111] The Company is working toward meeting this schedule and intends to do so.

The proposed program is also in direct response to recent Commission orders and other pronouncements that the Company provide more constant and better communication with the public and its customers. One recent Commission order, one Staff report and one audit report – all issued within the past year – emphasize the need for the Company to increase its communications specifically for the reasons given above.

First, in the Long Island City outage proceeding (Case No. 06-E-0894), Directive No. 14 requires the Company to have better communications with its customers. The directive states that Con Edison should:

> periodically notify its customers, not less than annually beginning September 15, 2007, through a variety of methods, including bill inserts, advertisements, and public service announcements, of the availability on its website of information during an outage . . .

(Exh. 246).

Second, in the Westchester outage proceeding (Case No. 06-E-1158), Staff's February 2007 Report[112] concluded (at 29) that the "Company's response to the July and September storms once again pointed out the need for increased and improved communication with customers, public officials, and the news media." In fact, that Staff report contained over 25 recommendations geared toward improving communication in one form or another.

Third and finally, the recent audit performed by Vantage on the Company's recent outages (in Westchester and Long Island City) found that the Company had made some progress in its communications and its website but concluded that greater improvements were necessary. "[A] key component of the restoration process is for customers to contact Con Edison. Customers are able to contact Con Edison by calling 1-800-75-CONED. This number has been

[112] Case No. 06-E-1158, July and September 2006 Severe Storms, A Report on Con Edison's Performance, Staff February 2007 Report.

heavily advertised throughout the Con Edison territory – in the media, local billboard, subway and bus posters, on company vehicles and customer bill inserts." (Vantage report, p. 149.) Vantage's statement about the significant presence reflects the increased spending that the Company has already committed in 2007. Even with this presence, the audit report states that Con Edison "should make the need to report outages more prominent in its advertising and customer outreach" (p. 152); and the Company's "website's effectiveness could be easily expanded" (p. 156). Despite the fact that it was issued nearly six months after this proceeding was initiated, comments like this one from Vantage support the need for the proposed program.

The Company's programs proposed are directly in line with and in furtherance of these objectives. The Staff Accounting Panel, relying on a discovery response to one subpart of a multi-part question, rejected the Public Affairs program change, claiming that the Company's claimed benefit is insufficient to support an increase in Public Affairs spending and denied the entire requested increase. (3583).

To begin, Staff considered only a portion of the Company's answer to the question "how would the increase (in Public Affairs spending) benefit customers?" (Exh. 96). The portion quoted by Staff (*i.e.*, "the benefit to the customer is that they will have access to more information on how they can take control of their energy usage") is not the Company's complete response to this question. (3583). Exhibit 96 demonstrates that the Company's full and complete response was that:

> the enhanced program will benefit Con Edison's customers because they will become more educated consumers of Con Edison's services. The information that will be presented to them may help reduce costs, avoid unnecessary delays in getting service or help them conserve energy. The benefit to the customer is that they will have access to more information on how they can take control of their energy usage.

Staff conveniently parsed the answer to justify its position. In a similar parsing, Staff placed two of the Company's recent ads into the record in this proceeding (see Exhibits 107 and 108). As part of the Staff Accounting Panel, Mr. Scherer testified that these two exhibits "really does not have anything to do at all with what was suggested in the Long Island City report and it would be a highly questionable advertising activity." (3671). Mr. Scherer's remark displays a misunderstanding of the intent of these programs.

Mr. Scherer's assertion fails to address the two goals inherent in an effective marketing and advertising campaign. The first is to provide the proper image and language that will capture the reader's attention and draw them to read the advertisement. The second goal is to sustain the campaign through the use of key recurring messages that will help the reader to remember the message. Recurring themes and messages in advertisements provide the recall that the reader needs to be able to use the information in the future. Increased exposure leads to higher recall by customers of the message they see and hear. Higher recall leads to higher awareness and customers act on the messages they remember – such as conservation tips or how to contact Con Edison during an emergency. In developing its marketing and advertising programs, Con Edison works with communication professionals to develop the most effective means for getting our message to stand out in the highly competitive New York media field. Working in the world's noisiest market, with so much information overload in various media, the Con Edison communications programs are developed to deliver the message as effectively as possible.

The two ads Mr. Scherer commented on are part of a series of advertisements aimed at establishing a recurring message through a sustained communications program. The advertisements provide readers with knowledge of the Company's infrastructure building

activity as well as reminding readers how to contact Con Edison. Both ads mention the Company's website and 1-800 number and that customers should contact the Company. These ads are part of a broader program. A review of an individual advertisement does not reflect the overall goals and purposes of a broader program that is attempting to capture the readers' attention and help them recall important messages. Staff was very selective in the ads it placed into the record – other advertisements, for example, "At Coned.com Knowledge Is Power" and "Customer Service Improvements" deal specifically with those issues. All of the ads are intended for the same purpose, to educate the public.

Second, nothing in Mr. Scherer's background or any other member of the Staff Accounting Panel (as set forth in the Staff Accounting Panel testimony) indicates any expertise in advertising. Nor did the Staff Accounting Panel offer any analysis or rationale to suggest that the Company was not providing useful and important information to the public through this advertising program.

As indicated above, in its various advertisements in the program, the Company reiterates and repeats its basic theme in each advertisement. (Exh. 107). This theme needs to be out there for people to understand and have it in mind before and/or during an outage or emergency situation. (1420-1421). Failure to consistently remind readers and customers will hinder the Company's ability to achieve the goals of its communication program.

Additionally, as was explained in the direct testimony of the Company's Accounting Panel, the Company plans to and has undertaken an extensive campaign in various media outlets, from daily print publications, to radio spots to outdoor advertising to placing ads in over 100 different community and ethnic publications. (1417). The Company also provided information about the campaign that it would undertake in the rate year. (Exh. 245). Absent additional

funding, this campaign will not continue and readers/customers in diverse communities throughout the service territory will no longer be reminded through a consistent media message and presence on how to contact the Company at any time or during an emergency.

The program change for Public Affairs also requested funding for website redesign and upgrade as well as funding for increased publication costs associated with the annual reports and other financial documents. The website enhancements are part of the overall advertising campaign and should similarly be included in the rate relief provided to the Company. Finally, the Company has experienced an increase in printing costs that should be allowed as well. These two components were unchallenged.

For all of the above reasons, the Public Affairs program change is proper and should be adopted.

10. <u>Tax Department Hiring</u>

In its direct testimony, the Accounting Panel explained the need for increased staffing in the Company's Tax Department, based upon a study of its tax function conducted by KPMG, a reputable global consulting firm. (1313). KPMG advised that the Company's staffing levels were not comparable with those of peer companies and recommended that the Company consolidate both Tax Accounting and Tax Compliance into one department, with a director or vice president devoted solely to tax matters. *(id.)* KPMG pointed out that the tax department needs more highly trained managers, more staff, and the staff needs more training and experience in order to perform tax accounting, tax compliance and handle controversy. At the time of the study, there were only three highly skilled personnel in the Tax Department and KPMG recommended that the Tax Department increase its staffing level by 10 employees. (Exh. 98).

Since that report was issued, the Company has been actively hiring experienced tax personnel to fill these additional positions while trying to replace retirements and transfers. In fact, at the time the record in this proceeding closed (*i.e.*, October 31, 2007), only three positions remained unfilled. (Exh. 244).

The Company included a program change for the electric department's share of these additional tax personnel in its rate electric filing, as it had done in its recent gas filing.[113]

Staff opposes the Company's request and recommends that the Company receive no funding for the additional tax positions recommended by KPMG. Staff's position is not only unreasonable, it is in direct conflict with the position that Staff recently took on this same issue in the Company's gas rate proceeding.

In the gas proceeding, the Staff Accounting Panel, which was comprised of four of the six Staff Accounting Panel members for this case, addressed the tax department hiring issue. (3654). They made a $58,737 adjustment – adjusting the salaries to be paid to these employees on the grounds that Staff believed the level reflected in the program change was "significantly overstated" and claiming that the Company's hiring was not proceeding as quickly as it should. (3653-3654; Gas Tr. 69-70 of Staff Accounting Panel in Case 06-G-1332). Staff did not question the need for these personnel, thereby tacitly acknowledging the need for this common program by recommending what the gas department's allocated share of these expenses should be.

In this proceeding, Staff inexplicably rejects the tax department hiring, stating "it does not see the benefit to the Company of adding these positions based solely on a peer group

[113] See direct testimony of the Company's Accounting Panel in Case No. 06-G-1332. (Gas Tr. 477-478).

analysis and without a cost benefit analysis."[114] (3568). Staff provides no basis for the differing positions taken in the two cases for a single common program premised upon actions taken by the Company in response to the KPMG study.

The basis for rate relief for these additional personnel in the Tax Department in both proceedings is identical. Cost-benefit analyses are not essential and in some contexts, are not useful. The KPMG review is, in effect, an expert review of a key function that relied not solely on benchmarking but also on KPMG's substantial and unquestioned expertise in terms of resources required for a corporate tax function in a complex corporate tax setting. The Company has continued to actively fill these positions in no small part based upon its reliance upon Staff's support for this common program in the gas proceeding, and the 2007 Gas Rate Plan Order, which reflects the gas department's share of these costs.

For all these reasons, the Commission should reject Staff's position.

11. <u>Shared Services</u>

In July 2006, the Company formed a shared services organization consisting of Business and Enterprise Shared Services. (1290). Shared Services is the concentration of Company resources performing like activities in order to service multiple internal customers with higher levels of service than has previously been the norm. (*id.*) The benefits of this structure are expected to include increased efficiency, better utilization of personnel, improved and integrated

[114] The Company would note that in its testimony, Staff complained that it had asked for and not received the KPMG study in the electric proceeding (something it did not request in the gas proceeding). In an oversight, the Company had not provided the study, which it noted in its rebuttal testimony that it had since been rectified. (1399). Now, the full KPMG study (except for redacted employee names) is in the record in this proceeding. (Exh. 98). The Company agreed to place this report in the record despite the fact that it is a self-critical analysis that is normally not made available consistent with Commission policy that disclosure would "provide a disincentive for utilities like the Company to continue such assessments." (3644-3645). On the record, Judge Bouteiller noted that he "consider[ed] this an isolated event … which has no relevance whatsoever to any future stance the Company may take or any future position you have." (3649). In addition, Staff, CPB and the other parties to the proceeding agreed that they would not refer to the Company's actions in this case in the event they sought disclosure of such a privileged document in a different Commission proceeding. (*id.*; 3645-3646).

systems, leveraged technology and improved effectiveness through standardization of processes and shared expertise as well as the use of best practices. (*id.*) These benefits will come from the function of the organization, which is to foster business process review and integration, facilitate standardization, and act as a liaison between in-house customers and the shared services organization. (1291).

The Company has assumed that the incremental cost of this group will be fully funded on a going forward basis by achieved savings by the fifth year of the organization but that it is in the early stages of this initiative and no savings are expected in the first year of the rate plan. (1300). The Accounting Panel noted that "these benefits are not easily achieved and will take time to realize." (1404). Nonetheless, the Company proposed to reflect in the rate year a reduction of 25 percent of the group's salary, or $222,000, to reflect productivity. The Company also included a normalization for the group (a labor and expense increase of $791,000, comprised of $542,000 to use external hires in other departments to replace management personnel that have now moved into the group, and $249,000 for other expenses). (1291; 1300; 1491). For the two adjustments in total, the Company requested an increase related to the Shared Services organization of $560,000.

Staff eliminated the entire cost of the Shared Services Administration labor expense, net of imputed productivity, making an $814,000 adjustment. (3574). Staff claims that the Company expects that the shared services organization will be self-funding through achieved savings within five years. (*id.*) Staff believes that the five-year period will be half completed by the end of the rate year, March 2009. (*id.*) Consequently, Staff concluded, without any basis,

that the "Company should be able to achieve significant program savings in an amount at least equal to the costs of operating a shared services administration."[115] (*id.*).

In rebuttal testimony, the Company explained that Staff's adjustment was inappropriate since "the Staff adjustment unfairly assumes productivity resulting from this effort is instantaneous. It is not." (1404). As indicated above, the Company expects to receive benefits over time that will eventually inure to the exclusive benefit of customers, but that there is no basis for reflecting an "unrealistic" level of productivity savings in rates at this time. (1404). Moreover, Staff's adjustment fails to take into account the fact that the Company incurred increased labor cost in forming the group, and in training the group in process review and project management. (1404-1405). This cost has been and is being incurred. (1405). Finally, Staff's adjustment did not take into account that one of the Shared Services employees works for Orange and Rockland. (1406). As such, the proposed adjustment would need to be updated to eliminate this employee whose time is not charged to Con Edison.

The Company recognized that there may be some savings and proposed 25 percent as a "fair projection" of the savings in the rate year. (1406). Staff has made an all encompassing adjustment that does not account for the time that it will take to develop the group and to implement the measures that will result in a long-term productivity improvement. Staff's overreaching adjustment should be rejected as it is "too much, too soon." The Company's 25 percent savings level is more realistic given the time it will take to develop the savings.

[115] CPB made a normalizing adjustment, which captured a portion of the shared services expenses but included other categories of costs. This is discussed in the normalizing adjustment section below.

12. Other Program Changes

Other contested program changes relate to additional personnel in finance/treasury, a meteorologist, vehicle fuel costs, and insurance costs. They are addressed sequentially below.[116]

a) Additional Finance/Treasury Department Employees

The Company included a program change to hire one employee for financial reports, one employee for regulatory filings, and three additional employees for the Treasury department. (1314). Staff adjusted the revenue requirement to remove these five positions, claiming that the Company either: (1) provided no rationale, (2) the rationale provided in the Company's work papers was insufficient, or (3) these positions which would be to rotate personnel through the department should not be "pre-funded" in rates. (3568-3570).

In both the Company's work papers and its rebuttal testimony, the Company detailed the reasons and the needs for these five employees.

For the financial reporting position, the Company explained that the new employee would be responsible for coordinating a complete "plain English" review of the Company's 10K, which would help 10K readers better understand the Company's business and financial performance (1401), which task cannot be handled at the current staffing level. (*id.*) This project is significant in light of the large amount of financing the Company is doing to support its construction program. (*id.*) Current staffing levels do not allow time to perform this extensive effort. (*id.*)

[116] There are a number of program changes that are uncontested. These uncontested program changes include, but are not limited to, the Expand data warehouse project (1302), staffing in the law department (1314-1315), the NERC Cyber Security Assessment (1303-1304), Supply Chain Replacement Study (1304-1305), the general ledger system study (1314), regulatory commission expenses (1298-1299) and the legal imaging and record retention projects. (1315-1316).

The Regulatory Filing position, which has been filled, is needed to handle the increasing level of regulatory filings for the Company's electric, gas and steam services. (*id.*) There is extensive work involved due to the volume of on-going and expected rate filings. (*id.*)

One of the three Treasury positions is for a lease administrator in real estate that will work on both the large number of real estate transactions as well as handling cellular antenna requests from wireless telecom providers. (1402).

The final two Treasury positions are to enable the development of financial expertise in the Company by rotating talented employees through the Treasury department, including Risk Management and Financings, which require extensive experience to acquire the knowledge necessary to fulfill the demands in these important groups. (*id.*)

For reasons unbeknownst to the Company, Staff did not pursue additional information as to these positions through the discovery process, as they did for virtually all other programs that were the subject of their review. As discussed above as respects recommendations by CPB to reject certain programs for lack of information, there is no basis for rejecting the Company's request for these additional personnel because a party (in this case Staff) chose not to seek additional information about these programs. The Company has justified the need for these positions and has already filled two of these positions. They should be allowed in rates.

b) <u>Meteorologist</u>

The Company's Infrastructure Investment Panel recommended funding for an individual that has a meteorological background and would supplement and interface with the existing weather forecasting services that the Company uses. (1854). This employee would review the subscription weather forecasts and perform independent forecasts, resolve any differences between the two forecasts while also providing a more real-time, up-to-the-minute enhanced

weather forecast, and therefore a better prediction of system demands, and act as a liaison throughout the Company for weather forecasting issues. (1854-1855). Another benefit would be the Company's ability to avoid or reduce the time that a thunderstorm watch is declared. (1855). The Panel explained that while the weather subscription services perform reasonably well on a routine basis, they often lack expertise when it comes to the localized effects of weather conditions in the New York City and Westchester county areas. (1856). In addition to increased accuracy, this employee would be able to update local area weather pattern changes quickly, before the subscription services do so. (1856-1857). In fact, the Company believes that the weather service updated forecasts lag weather patterns by several hours. (*id.*) Consequently, the Company requested a $150,000 program change to hire such an individual. (1857).

Staff's Accounting Panel rejected the program change. They do not agree that a single Company meteorologist will be able to more accurately forecast local conditions by independently reviewing other forecasts and that the New York metropolitan area receives significant coverage from the weather services. (3567). AGC witness Bush agreed that a meteorologist position was necessary and recommended that the Company "should share" its forecasts on a real time basis with In-City generators. (1584). Mr. Bush claims that if the Company provides this information to In-City generators, customers will benefit. (1585).

In rebuttal, the Infrastructure Investment Panel reiterated the reasons for the meteorologist. (1923-1925). The Panel explained that by using the subscription weather forecasts, the Company's operating staff may, for example, "unnecessarily react to potential events … ." (1924). In effect, this would permit the Company to improve its operations by being more proactive in reacting to severe weather conditions because it would have better information. (1925). In fact, both Staff and the Company agreed that information that the

Company obtained from a non-local commercial weather service in at least one of the 2006 storms failed to accurately forecast a change in the direction of the storm.[117]

On cross-examination, Mr. Longhi reinforced the reasons for staffing this position. He explained "our intent by having a specifically trained individual in this position is to be able to take the various inputs we get, make sure they are specific to our service territory, and up-to-date in terms of our service territory, and to advise the operators in terms of their planning and operations of the system." (2067). Moreover, he noted that the decision to hire a forecaster was a decision that each generator needs to make. (2076).

The evidence shows that staffing this position has the potential to provide material benefits to customers that should not be lost. Accordingly, Staff's adjustment should be rejected.

In addition, the Company should not be required to share any forecasts with In-City generators as it does not provide weather forecasting services to third parties. (Exh. 149). AGC has the same opportunity as the Company to avail itself of the services of an in-house meteorologist. AGC has provided no reasonable basis for requiring the Company to provide it with a weather forecasting service.

c) <u>Vehicle Fuel Costs</u>

In the update stage of this proceeding, the Company submitted an update to vehicle fuel costs, requesting approximately a $1 million program change based on increased fuel usage due to a larger fleet and an increased cost of fuel in the rate year. During the course of the hearing, the Company was made aware of an error in this update. The Company was given the opportunity to correct the update, which shows an increase of approximately $300,000. (5545-5547). The Company is unaware of any opposition to this update. If there is opposition, the

[117] Westchester Outage Report, p. 11-12.

Company will address it in its Reply Brief. The Commission should adopt the Company's corrected, updated fuel costs.

d) <u>Insurance Costs</u>

The Accounting Panel sponsored a program change to the costs of the Company's insurance requirements. The update increased insurance costs by $5.354 million to address expected increases in premiums for property and liability insurance and to make an adjustment for Worker's Compensation costs. (1294). The Panel testified that this increase was net of $4 million in refunds from Nuclear Electric Insurance Limited ("NEIL"), the amount that it embedded in base rates to reflect this refund. (*id.*)

Staff and CPB propose adjustments to the Company's projected insurance expense. Staff's Accounting Panel claims that based on the latest known premium changes provided by the Company and a declining trend of insurance costs, a 2.9 percent growth rate should be applied to insurance costs, reducing this expense by approximately $3.75 million. (3583-3585). In addition, Staff reduced this expense by $61,000 to reflect the insurance costs associated with retired officers. (*id.*)

The Company's update provided for a $1.2 million reduction in this program change to reflect the latest known premiums (1435). As explained below, no further adjustment is warranted.

CPB proposed two adjustments to the Company's insurance expense.[118] CPB's first adjustment removes the entire program change for insurance increases, claiming that the Company did not support the requested increase. (3225-3226). CPB claims that the Company's discovery responses showed a declining trend in these costs. (*id.)*

[118] The Company's arguments on the insurance cost adjustment apply equally to Staff's adjustment.

CPB's second adjustment eliminates the costs for Directors and Officers ("D&O") liability insurance, which they assert should not be funded in rates. (3227-3229). CPB claims that this expense represents 22.6 percent of the total insurance expense and that this "insurance is designed to protect directors and officers from inappropriate activities they may have participated in and/or from decisions that they made." (3227). CPB announces that "the ratepayer receives nothing" from this expense. (*id.)* CPB claims that other jurisdictions have recently disallowed a portion of these costs. (3228). They also claim that directors and officers receive generous benefit packages, including generous stock options, and that somehow they are being compensated twice as a result of this insurance. (3228-3229). None of CPB's arguments provide a basis for adjusting the Company's proposed insurance expenses.

As to the issue of the level of the program change, in rebuttal, the Company's Accounting Panel explained that it provided information in a discovery response to CPB demonstrating how the insurance premium forecast expense was developed (1435), that it was the best estimate for 2007 based on the market at the time, and that it reflected the input of the Company's insurance brokers, consideration of recent events (like the recent spate of hurricanes that have affected the insurance industry) and the Company's own loss experience. (*id.)* The Accounting Panel noted that its update had decreased the cost by $1.2 million and that its update reflects the known premiums for 2007 and the latest 2008 forecast. *(id.)*

The Company's projections are based on the best available information, unlike the adjustments of Staff and CPB. Staff's historic average of insurance increase levels fails to take into account that every year is different and in each year, insurers face new and/or different risks. Insurers react accordingly and therefore projected insurance costs cannot merely reflect an historical average. CPB's arbitrary dispensation of the entire increase because they believe the

estimate is too high or that the Company has not supported this estimate does not withstand even superficial scrutiny. ((3225-3228). CPB's beliefs cannot alter the indisputable reality that insurance costs are increasing every year. And, as indicated above, the Company did demonstrate the basis for its estimate. (1435). CPB's position is inherently unreasonable and should be rejected.

As to D&O insurance, the Company's Accounting Panel explained that D&O insurance represents a reasonable and necessary cost of providing service to customers and that the recent large increases in these costs are driven by events outside of Con Edison's control and not through any fault of the Company's management. (3225-3228). On cross, CPB agreed that major companies all have this type of insurance (3329) and that if the Company opted to tell directors and officers to pay for their own insurance, then "they may want higher compensation." (3326-3327). Since CPB acknowledged that compensation for officers should be included in rates, proposing to exclude the cost of D&O insurance is circular. (3328).

CPB also conceded that D&O insurance not only protects directors and officers but also covers the Company's cost of defending directors and officers against lawsuits that are later found to be without merit. (3329). In addition, had CPB reviewed any standard D&O policy, it would have discovered that the standard policy excludes criminal acts. That is, D&O insurance is not intended to protect bad actors.

The Accounting Panel explained that Con Edison cannot retain current or attract new qualified individuals to act as officers or directors without providing D&O insurance.[119] (1434). It is a standard cost incurred by major companies, particularly in light of today's litigious

[119] On cross, Staff inquired as to whether the Accounting Panel had a study to support this statement. (1514-1515). The Accounting Panel explained that this statement was based on discussions with Company personnel (1514) and the question posed was theoretical. (*id.*) Given CPB's admission that major companies all have this insurance, it stands to reason that having this type of insurance is necessary to retain qualified personnel.

corporate environment. Contrary to CPB's position that "customers should not pay for it because they don't benefit," there is a customer benefit in the Company's retaining and attracting qualified individuals. CPB provides no justification for either eliminating D&O insurance or seeking to have that cost funded outside of rates. CPB has not demonstrated that the Company should do without essential insurance protection or to deny rate recovery for what is indisputably a legitimate cost of doing business. Accordingly, D&O insurance is an expense that should be borne by customers.[120] It is also fair to assume if the Company were to increase the salaries of directors and officers to enable them to purchase D&O insurance on an individual basis, rather than through a group plan, these aggregate costs (which should be borne by customers) would be higher, since the cost of insurance under group plans is typically less expensive.

As such, CPB's adjustment should be rejected.

e) <u>Training Costs</u>

Company witness Mueller, the Director of The Learning Center ("TLC"), Con Edison's state-of-the-art training facility, presented the projected hiring and training costs associated with both current and new employees; strike contingency expenses; and the costs of the new Payroll System being implemented by the Company (109-118). In total, Mr. Mueller demonstrates the need for approximately $9.9 million in program changes, which are unopposed and should be adopted.

B. <u>Other Operating Revenue</u>

Through its Exhibit 84, the Company's Accounting Panel demonstrated that the electric department's Other Operating Revenues would decrease by $469.314 million from the historic year level of $620.830 million to $151.516 million in the rate year. (172-1283; Exh. 84, Sch. 1,

[120] As discussed *infra* in the context of executive compensation, there is no basis for disallowing what is a legitimate business expenditure. *See* Case No. 91-E-0462, Consolidated Edison Company of New York, Inc. – Electric Rates, <u>Opinion and Order Adopting Settlement</u>, Op. No. 92-8 (issued April 14, 1992), 32 NY PSC 441, 488.

page 2 of 6). This decrease of $469.314 million is primarily driven by the removal of $487 million of non recurring items. These non-recurring items include, but are not limited to, Transmission Congestion Credit ("TCCs") Auction proceeds ($155,455,000 decrease), T&D expense deferrals ($115,419,000 decrease), the amortization of World Trade Center and Indian Point Losses ($101,242,000 decrease) and other smaller items, including but not limited to, miscellaneous tariff changes ($248,000 increase), interdepartmental rents ($1,813,000 increase) and Cash Point losses ($10,843,000 decrease) and other Regulatory Accounting entries to properly record transactions resulting from the various provisions of the current rate plan.

Staff's Accounting Panel took issue with adjustments that the Company made to Other Operating Revenues for the rate year in the areas of late payment charges ("LPCs") ($692,000 increase), fuel management program ($39,000 increase) and ADR Tax Benefits.[121] The Company has accepted these Staff adjustments. Moreover, the Company does not object to Staff's method of calculating LPCs.

Staff proposed other adjustments to Other Operating Revenues that the Company does not accept. Staff made adjustments to the level of World Trade Center costs/reimbursements to be included in rates and the time period over which credits for DC incentives and Excess Deferred SIT should be returned to customers. Staff also suggests the treatment for any resolution of the 263A deductions.

Westchester and NYPA proposed that additional revenues from TCC Auction Proceeds be embedded in rates. Except as discussed regarding ERRP maintenance in this section, the

[121] The ADR tax benefit refers to a correction to the amortization of deferred ADR tax credits with interest applicable to the April 2005 – March 2008 time period. As a result of an accounting error, these credits were not previously reflected in the Company's revenue requirements in Case No. 04-E-0572. The Company has proposed to pass these benefits back to customers over three years, which results in a reduction to the annual revenue requirement of approximately $27 million per year. The Commission's Order issued on September 4, 2007 in Case No. 06-E-0990 directed that these credits be returned to customers.

Company's remaining adjustments to Other Operating Revenues are uncontested and should be accepted.

The adjustments at issue are discussed below.

1. <u>World Trade Center Costs/Reimbursements</u>

Pursuant to the associated Commission orders involving the September 11, 2001 terrorist event, the Company has been deferring costs associated with the restoration, rebuilding and interference expenses associated with the attack. (2438). The federal and state governments[122] have classified the utility expenditures eligible for reimbursement in connection with the event into three main classes:

Category 1 – Emergency Response and Temporary Restoration;

Category 2 – Permanent Restoration and Infrastructure Improvements; and

Category 3 – Service Interference (relocation of Company facilities). (*id.)*

The Company has been recovering World Trade Center related costs through one of several methods: (1) insurance proceeds for the damaged substation; (2) funding through the Lower Manhattan Development Corporation ("LMDC"), which in partnership with the Empire State Development Corporation ("ESDC") and New York City Economic Development Corporation, has disbursed portions of the available federal funding; and (3) a certain level of these costs through electric, gas and steam rates.[123] (2438-2444).

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[122] See Lower Manhattan Development Corporation in Partnership with Empire State Development and New York City Economic Development Corporation, Partial Action Plan for Utility Restoration and Infrastructure Rebuilding, as submitted to HUD (as of August 21, 2003).

[123] The Company is also a plaintiff in a lawsuit against a number of parties, including the airlines, the Port Authority, the building owner and numerous others. Mr. Rasmussen testified that in the event that the Company receives any recoveries from this lawsuit, "we first have to pay back the Government for what they've given us and then the balance would be available for our ratepayers." (2550). In fact, the LMDC/ESD/NYCECC Action Plan (at p. 8) notes that if a recipient of these funds receives other recoveries that result in the total reimbursement exceeding its losses, excess funds will be returned to the LMDC/ESD.

Regarding the insurance recoveries, the Company has received and applied against the deferred accounts approximately $78.5 million received from insurers. (2439). Any additional funding from insurers is highly speculative.

Regarding the federal funding, the LMDC and ESDC have developed a partial action plan to disburse the $750 million in federal funding that was allocated for reimbursing utilities. (2438-2439; 2462-2463). The federal funds are being allocated based on the three main categories of costs noted above. (*id.)* The deadline for applying for category 1 and category 2 funds has passed.[124] *(id.)* As Mr. Rasmussen noted, the Company has received $80.2 million in Category 1 funds, of which $62.7 million is applicable to electric, and $176.3 million in Category 2 funds, of which $159.8 million is applicable to electric. At this point in time, the Company does not expect any further major reimbursement in these two categories. (2462-2463).[125]

This leaves one category of federal funding that remains outstanding – Category 3, which Mr. Rasmussen testified has an allocation of $60 million in total for all applicants. (2439; 2463). Mr. Rasmussen explained that the Company's expenditures in this category as of May 2007 well exceeded that amount. (*id.)* Accordingly, the Company will not receive compensation for the total amount of its interference-related World Trade Center deferred costs.

Based upon the foregoing, the Company proposed a thirty-six month recovery for carrying charges and expenses incurred through March 31, 2008 that would normally have been expensed. (2440). In the same vein, the Company seeks a thirty-year recovery for capital items.

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[124] The Company understands that there are utilities that are contesting their disbursements and as a result, for some utilities, final allocations have not been made yet. Verizon is the other major recipient of these funds.

[125] On cross, Mr. Rasmussen conceded that the Company has a pending appeal of some Category 2 costs. (2498). While he was unsure of the amount at issue (which is approximately $10-15 million), he explained that customers would be reimbursed if any additional funding was received. (2499). He noted that the appeal was filed to protect both the Company and the customers. *(id.)*

(*id.)* The Company also noted in both Mr. Rasmussen's and Mr. Gencarelli's testimony that since the deadline for category 3 costs is December 31, 2007, the Company should start treating World Trade Center related costs as normal ongoing capital and operating interference expenses. (*id.)*[126] This is addressed in the discussion on Interference costs above.

Three parties – CPB, Westchester and the Staff Accounting Panel – commented about the level of World Trade Center costs. Two of the three parties – CPB and Westchester – advocated that the Company continue to defer all of these outstanding expenses until all avenues of recoveries are exhausted. (5452; 4691-4693). Staff's Accounting Panel argues that since the reimbursement picture is unknown, the Company should continue to recover these costs at the current level of $14 million annually. (2462).[127] Their positions should be rejected.

None of these parties has demonstrated that the Company will likely recover from the federal government, from insurance companies, or from defendants in lawsuits any material portion of the current outstanding amount of unrecovered World Trade Center related costs, never mind any additional costs the Company incurs. Nor does the Company agree with Staff that the reimbursement picture is "unknown" or that there are additional funding sources available, as the possibility of additional funding is speculative and anything received will be returned to customers (to the extent not otherwise due the federal government in the case of the lawsuit).

Mr. Rasmussen explained that he expects no more insurance reimbursements and that reimbursement of Category 1 and Category 2 amounts are complete, except for a minor amount

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[126] These expenses in the linking period would be deferred and added to the outstanding balance.

[127] Staff complained that it was not provided on a timely basis with information related to a reimbursement check from the federal government for WTC-related expenses. The Company demonstrated that Staff was made aware of the reimbursement check at a date earlier than that alleged by Staff, that not reflecting the reimbursement in the August preliminary update was inadvertent, and that this reimbursement was included in the Company's September update. (2463-2464; 2501-2503).

being challenged in Category 2. (The total recovery for these three areas was $239 million through August 2007, excluding interest, of which electric is $210.0 million as compared to total expenditures of $513.0 million, excluding interest, of which electric operations is $413.8 million.)[128] As explained above, federal funding for Category 3 is limited to $60 million for all affected utilities, with the Company's expenses alone being greater than that amount.[129] To date, the Company has expended $184 million on Category 3 expenses reflected in the $513 million above, of which electric is $124 million.

As Mr. Kane of the Company's Accounting Panel noted during cross, "The Company is requesting a three-year recovery period, so that by the time we would get full recovery of those costs, ten years after the event, that that is more than a reasonable amount of time to be out-of-pocket for those types of expenditures. There is no reason to protract it any longer than that." (1537). He further explained that "Those costs … have built up over six years … These are expenditures that occurred in 2001 and we're seeking to recover them. And ten years, we believe, is more than enough time." (1538).

For the reasons set forth above, there is no basis for the Company to continue to defer these costs.[130] The Company has demonstrated that most, if not all, of the remaining expenses incurred by the Company should now be recovered from customers over the three- and 30-year periods proposed by the Company for expense and capital amounts, respectively. Having

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[128] Currently, as of August 2007, the Company has deferred approximately $160 million in electric World Trade Center expenditures which includes $60 million that has been transferred to plant in service. (2461). The Company proposed an annual recovery level of $34 million in its update. *(id.)*. This would result in the recovery being completed by the end of the proposed three-year rate plan period. Simple mathematics reveals that Staff's approach of continuing the $14 million annual recovery would delay the entire recovery for at least another 8-10 years.

[129] Also, the September 11, 2001 litigation is in preliminary stages, significant recoveries are not expected from this suit, and, most importantly from a ratemaking standpoint, any recoveries will be credited to customers.

[130] Westchester's position is even more egregious, suggesting that there be no recovery of these costs, only a continued deferral. (5452). There is no justification for such an outrageous position. CPB would allow recovery over 10 years.

expended these funds, the Company should be permitted to recover these costs in a timely manner. As Mr. Kane noted "there's no reason to protract it …" (1537).[131]

One final note, allowing for current recovery of these costs promotes intergenerational equity and financial integrity, in that current customers pay for current costs and the Company is not required to finance these costs.

2. <u>DC Incentive/Excess Deferred SIT</u>

As to the Direct Current ("DC") incentive, the Company collected a surcharge from DC customers that funded an incentive conversion program, *i.e.*, DC customers were provided an incentive to change from DC to AC service in an effort to discontinue the DC system. (3556-3558). The DC system was recently eliminated, and the Company projects that there will be approximately $9 million remaining in the incentive conversion fund after considering all potential remaining costs. (3557).

The New York State Corporate Income Tax level was reduced from 7.5 percent to 7.1 percent, effective January 1, 2007. That resulted in approximately $12.5 million of Excess Deferred SIT credits on the Company's books since prior deferred tax balances were calculated at the higher statutory rate (3624-3625), and an Excess Deferred SIT debit of approximately $1.4 million.

While Staff and the Company agree that these credits, totaling a little over $21 million,[132] should be refunded or credited to customers, the Company disagrees with Staff as to the time period for such refunding or crediting.

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[131] As noted above, additional recoveries from other parties in excess of the Company's unrecovered losses would be first returned to the federal government and if anything is left, credited to customers.

[132] In calculating its recommended adjustment to the revenue requirement, Staff's computations did not reflect the federal income tax impact of amortizing the deferred state income tax balance. As a result, Staff's adjustment to other operating revenues for the SIT tax benefits should be reduced from $20,745 million to $12,023 million, a net reduction of $8,722 million. A corresponding adjustment is also required in rate base to decrease the balance of

Staff recommends that they be passed back in the rate year as an offset to the revenue requirement. (3558; 3624-3625). The Company believes that these credits should be returned to customers over a three-year period. (1423). This time period is similar to the Company's three-year amortization of deferred charges. (*id.)* More importantly, passing back the credits over a one-year period will require an immediate $21 million increase in rates in the following rate year. The Accounting Panel testified "rates would be artificially low for the period of one year and then rise dramatically thereafter as all available credits have been exhausted." (1423-1424). A three-year phase-in would only require a $7 million increase at the end of the third year. Moreover, Staff's position is inconsistent with the position it took regarding the ADR tax benefit, agreeing that a three-year amortization is appropriate for that refund, which is of a greater dollar value. (3555-3556). The Company's three-year proposal balances the accounting related to these credits and debits and makes the appropriate calculation (and refunds/surcharges) in a reasonable period. The Company consistently applies a three-year amortization proposal to its credits and debits and attempts to minimize the need for adjustments. These credits and debits are difficult to forecast and in some cases, unknown.

For all these reasons, the Company's three-year phase-in proposal should be adopted.

3. <u>Transmission Congestion Contracts</u>

The Company receives revenues from the sale of Transmission Congestion Contracts ("TCCs") in the New York Independent System Operator's ("NYISO's") TCC auctions. These TCCs are purchased by market participants seeking to hedge their costs when the Company's transmission lines are used during congested periods. Under the 2005 Rate Plan, $60 million of revenues from TCC auctions were imputed as part of the Company's revenue requirement.

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deferred income taxes by a net of $2.633 million. This error was discovered after the close of the record and the Company has notified the DPS Accounting and Finance Department Staff.

(1396). Any additional TCC revenues received were flowed back to customers through the MAC, which means that only full service customers received credits above the $60 million. (1398). The Company's initial testimony proposed to continue to: (1) impute $60 million of TCC revenues and (2) to continue to credit customers with any additional revenues through the MAC.

Two parties – NYPA and Westchester – suggested that a higher level of TCCs should be imputed in rates. (4648; 5460-5461). Both NYPA and Westchester state that over the past three years, the Company has received TCC credits an average of $150 million annually and that this higher amount should be included in rates to mitigate the rate increase. (*id.)* NYPA has a second, and more substantive reason for its proposal – to decrease NYPA's share of any rate increase at the expense of other customers, by receiving a greater proportion of TCC proceeds. (1548-1549).

As noted above, under the 2005 Rate Plan, TCC credits in excess of $60 million are passed back to Con Edison customers currently through the MAC. Of the first $60 million imputed in rates, NYPA is entitled to receive 14.22 percent or approximately $8.5 million. (2005 Rate Plan Order, App. I, pp. 76-77). The rate plan explicitly states that "the NYPA class will not share in any subsequent reconciliation of forecasted-to-actual TCC auction proceeds during the Electric Rate Plan." (2005 Rate Plan Order, App. I, p. 77). NYPA provides no basis whatsoever for changing the current allocation of TCC credits as between NYPA and other customers. NYPA seeks to accomplish this reallocation in the guise of recommending that a higher level of TCC credits be imputed in rates subject to full reconciliation.

The Company opposes this increased imputation level for several reasons. As the Company's Accounting Panel explained in their rebuttal testimony, there is no basis for

assuming that this $150 million level will be reached during the rate year. (1396). That is, in developing the imputation level, the pending proceeding on TCCs before the FERC must be considered. In October 2007, the NYISO filed a proposal with FERC to sell a significant portion of the TCCs available on a long-term basis. (1397). The FERC's decision in this proceeding could have a significant negative impact on the level of TCC revenues received by the Company from the NYISO auctions. For example, FERC may adopt the PJM's method for handling TCCs, which could reduce the level of revenues available for customer credits. (*id.)* Accordingly, the level of Con Edison's future TCC revenues is very uncertain at this time. (*id.)* The Company's Accounting Panel noted that NYPA participates in this proceeding and should be well aware of this on-going debate. (*id.)* Moreover, NYPA provided no compelling evidence that this level will continue during the rate year.

Consequently, the level of TCC auction revenues is uncertain and subject to a significant amount of risk. Therefore, the amount embedded in rates should be the $60 million proposed by the Company. Customers will get the full benefit of any additional revenues received by the Company, should the $60 million estimate turn out to be understated. The proposal to more than double the current amount imputed to rates is not reasonable.[133] (1398).

Moreover, as explained above, NYPA has not demonstrated that it is entitled to any greater level of TCC credits than it currently receives. There is no record evidence that establishes a basis for either changing the current allocation methodology or even revisiting that methodology.

[133] Moreover, should the imputation be increased to $150 million (or some other amount), at the end of the rate year, if the amount imputed in rates is not received, the Company should be permitted to collect through the MAC the difference between the amount received, for example $90 million, and the level imputed in rates, for example $150 million. In this example, the Company would to collect $60 million in the MAC after the end of the first rate year.

Under NYPA's proposal, any increase above $60 million imputed in rates would guarantee NYPA an additional share of TCC credits whether or not actual credits are achieved, since the reconciliation to actual costs would be through the MAC, which NYPA does not pay. Accordingly, should the Commission nonetheless decide to impute in rates more than $60 million of TCCs, any amount imputed above $60 million should be allocated in the final rate design so as to maintain the status quo as between NYPA and other customers as respects TCC credits.

4. <u>Deferred Taxes – Section 263A</u>

The Company has an on-going pending disputed tax deduction before the Internal Revenue Service. (3631-3632). This tax deduction refers to tax accounting changes under 263A of the tax code. (3631). Under this section, since 2002, Con Edison has been using the "simplified service cost method," which effectively allows the Company to obtain expense deductions for costs and assets that would have otherwise been depreciated over a 15-20 year period. (*id.)* The IRS has challenged the Company's deduction for the years 2002 and beyond. (3631-3632).

Staff notes that the Company is working with the IRS to resolve this issue and suggests that no adjustment to rate base be made for the average amount of accumulated deferred taxes of $298 million at this time. (*id.)* Staff suggests that since there is a potential for a significant disallowance, the Company should provide an update based on the latest available information. (3633). Staff requests that this update reflect any related offset to ADR/ACRS/MACRS related rate base balances. (*id.*) More important, if a resolution with the IRS is reached, Staff recommends that the Company notify the parties and provide updated information. (*id.*)

The Company agrees to Staff's proposal if a resolution with the IRS is reached (1517), which is the same treatment that was accorded this issue in the 2007 Gas Rate Plan. At this time, the Company can report no new developments, except that it continues to accrue carrying charges on the deferred balance as has been suggested by Staff.

C. Taxes Other Than Income Taxes

1. Property Taxes

Mr. Hutcheson explained the projected level of property taxes for the rate year and also demonstrated the Company's comprehensive efforts to attempt to minimize property taxes.[134] He also updated the projected level of property taxes in the update phase of the proceeding. In his direct testimony, Mr. Hutcheson estimated that the Company would pay the City of New York and other municipalities approximately $781.7 million in property taxes during the rate year, of which $700.1 million would be paid to the City of New York. (674). Mr. Hutcheson described his methodology for arriving at that amount.

As a starting point, he considered the Company's 2006-2007 final real estate and special franchise values for New York City and the Company's actual 2006 Westchester taxes. (674-675). For New York City property taxes, he reviewed the Accounting Panel's forecasted estimate of net plant being added in the City and developed the estimate for these taxes based on past experience. (675). For Westchester County, due to the numerous municipalities involved, he testified that he simply escalated the actual 2006 taxes by a percentage he has developed based on past actual experience. (*id.)* For both New York City and Westchester property taxes, Mr. Hutcheson then reduced these amounts by the estimated tax savings for known assessment

[134] Mr. Hutcheson explained that the Company focuses on the fairness of assessments in a particular municipality. The Company applies for tax exemptions and benefits, such as the Industrial and Commercial Incentive Program ("ICIP"), where possible. Additionally, the Company challenges assessments and seeks to resolve the challenges either through a settlement agreement with the municipality or through litigation. (675-681).

decreases then were known. (*id.)* Based on these calculations, he arrived at his initial forecast level.

In the forecast, Mr. Hutcheson revised his original property tax forecast based upon intervening events. He explained that since the initial filing, New York City issued its final assessed values for fiscal year 2007-2008 and final tax rates that resulted in significant tax decreases. (688). The updated forecast also included the latest estimated tax benefits associated with the Mott Haven, Jamaica, Goethals and Hudson Avenue East Substations ICIP's tax abatement that were not known at the time of the original filing benefit. (689). As a result, Mr. Hutcheson forecast a $26.4 million reduction from his original forecast, bringing the expected rate year property tax level to $755.3 million.

The only party challenging the Company's property tax forecast is Staff, who accepted the updated numbers but made a further downward adjustment of $1.771 million, bringing the forecasted property tax level to $753.6 million. (3607-3610). Like Mr. Hutcheson, Staff computes forecasted tax rates for New York City based on five years of historical tax rates. It is the treatment of an unusual and significant 18.5 percent mid-year tax rate increase in fiscal year 2002-2003 where Staff and the Company disagree. As Mr. Hutcheson testified, he ignored the 18.5 percent mid-year rate increase as not being representative of a "normal" tax increase. Its inclusion of past experience to develop an average rate change would not be proper simply because of its magnitude and because of the unusual situation that resulted in two rates being effective for a single fiscal year. In its development of the tax rate change, Staff elected to use only the second, much higher rate for the 2002-2003 fiscal year. Mr. Hutcheson explained that Staff could have at least developed an average rate for that fiscal period which would have resulted in a lower rate for the year, but instead elected to use the final, very high rate. The

effect of using that higher rate was to force a decrease in the next year's percentage change because rates had to correct themselves after such a large increase. Therefore, use of that higher rate caused the Staff methodology to produce an artificially low percentage change in the five-year average. Staff's cherry-picking methodology, and therefore its proposed adjustment, should be rejected. The Company's proposal to reconcile property taxes is discussed later in this Brief.[135]

2. Other Taxes

The Accounting Panel addressed the other taxes that the Company is projected to incur in the rate year. These taxes include revenue taxes, payroll taxes, and subsidiary capital tax (a New York City tax). (1284-1287; 1384). No adjustments to these estimated tax levels were proposed, except to reflect other proposed adjustments that may be adopted by the Commission (*e.g.*, if the number of employees is reduced, the associated payroll tax should be reduced accordingly). (3575).

D. Normalizing and Other Adjustments

The Company made several normalizing adjustments in an attempt to bring the historic year's spending levels for certain categories of costs more in line with what is expected to occur in the rate year. For example, the Company does not expect that an incident similar in scope to Long Island City ("LIC") will occur in the rate year. Thus, the Company removed the entire O&M cost relating to LIC of $47.120 million from the rate year forecast. (Staff also adjusted the level of capital expenditures in the rate year, which is discussed below).

[135] The Company also proposed to continue the 86/14 customer/Company sharing mechanism for property tax refunds and credits in the 2005 Rate Plan (2005 Rate Plan Order, App. 1, p. 17). (2436). Staff agreed with the Company's proposal (3611) and no other party expressed opposition to that proposal. Accordingly, it should be adopted.

Nor does the Company project that it will experience storms to the same level that it did in 2006, and made a normalizing adjustment to remove two-thirds of storm-related costs incurred in the historic year. (The Company did request that a storm reserve be established, which is discussed below.)

Adjustments to the Company's normalizations were made by the Staff Accounting Panel and CPB. Staff Accounting Panel made an adjustment for executive officers; during the course of the hearing, Staff corrected their adjustment from $4.9 million to $769,000. The Company agrees with the adjustment, as corrected. Staff also suggested removal of the capital costs associated with the Long Island City event (discussed below) and proposed an adjustment to the Shared Services organization (discussed above). CPB's adjustments focused primarily on labor, overtime and management compensation.[136]

1. <u>LIC Capital Costs</u>

Included in the Company's capital expenditures, depreciation amounts and carrying costs are costs associated with the repair, replacement, restoration and planned work for Long Island City after the outage that occurred in July 2006 in portions of that network. Staff objected to the inclusion of these costs in the rate year on the grounds that this is the subject of a pending Commission proceeding, which is investigating the prudence of the Company's actions related to this outage.[137] (3625-3626). Since there is an on-going proceeding, Staff maintains that it is premature for the Company to request the recovery of or the return on these investments. (3626).

[136] The Company's labor normalization was approximately $3.4 million, comprised of, but not limited to, staff for Environmental Health and Safety and Law.
[137] Case No. 06-E-0894.

Staff therefore makes several recommendations regarding these costs. First, Staff recommends that all costs related to the outage be removed from the revenue requirement. (3626). Staff claims that there are $49.6 million in investments in the Long Island City network that should be excluded. (3627). Second, Staff suggests that if the prudence proceeding is concluded prior to the Commission decision in this proceeding, the information in this proceeding should be updated to reflect the outcome of the prudence proceeding. (3626). Third, if the prudence proceeding is not completed, then Staff recommends that the Company be permitted to defer carrying charges on the net plant balance and to defer related depreciation accruals on the plant additions. (*id.)* Staff notes that in addition to the $49.6 million, the Company has accrued $3.99 million in its depreciation reserve and is seeking a depreciation allowance of $1.05 million for Long Island City investments. (3627).

Staff also takes issue with accruing carrying charges on the Company's investments in Long Island City because of the existing capital reconciliation mechanism in the current rate plan. (3627). Staff has two recommendations related to the capital reconciliation mechanism. (3630). For the second rate year of the 2005 Rate Plan, Staff proposes that the Company reverse the credits equal to the carrying charges applied to the outage related costs. Similar to Staff's earlier position, if the costs are found to be prudent, the credit would be restored. (*id.)* If they are not, they would be available for future Commission disposition. (*id.)* For the third rate year, Staff suggests that these carrying charges be separately deferred pending the outcome of the prudence proceeding. (*id.)*

The Company believes that the Commission will ultimately determine its actions during the Long Island City event to be prudent. That being said, pending a Commission determination in that proceeding, the Company does not object to the rate treatment proposed by Staff. The

Company will work with Staff to make the appropriate adjustments prior to any final Commission order in this proceeding as well as in the prudence proceeding.

It is important to mention that the Company's agreement to this rate treatment must not be misconstrued. That is, the Company continues to believe that it is entitled to full recovery of and a full return on these investments.

2. <u>Program Change For Employee Payroll</u>

CPB makes an adjustment of $2.45 million, or what they term as five percent of the Company's total program change request of $49 million. (3218). CPB claims that the Company was not clear in the number of employees being requested to fulfill the various proposed program changes. *(id.)* They further claim that the exhibits provided by Mr. Mueller provide insufficient detail to reconcile and/or link the additions to the program change or normalization. This $2.45 million adjustment is improper.

The purpose of Mr. Mueller's exhibits was to present overall projected hiring levels. (3217). The exhibits, workpapers and data responses of other Company witnesses explain the nature of individual program changes, including the need for additional employees. CPB's complaint here must be rejected for the same reasons discussed above regarding program changes. That is, the Company provided comprehensive support for its program changes and normalizations and these changes cannot be rejected based upon belated and unfounded claims by CPB that it did not receive adequate information or that the information was not presented to it in a certain format. The Company's workpapers explained the program and the number of employees associated with the program change. The Company fully documented its needs for additional employees and CPB's reasoning does not withstand even the slightest level of scrutiny. This adjustment should be rejected.

3. **Overtime**

The CPB Panel proposed two adjustments to the Company's level of overtime. (3218-3221). CPB arbitrarily: (1) reduced the escalation that the Company applied to electric operations overtime (they take 6.39 percent of the $65.9 million in payroll to arrive at a decrease of $4.2 million); and (2) removed 10 percent of the payroll (*i.e.*, $6.59 million) to reflect the fact that the Company expects significant additions to its work force and to eliminate "some of the extra overtime for unusual storms." *(id.)* CPB alleges that the Company has not justified the large increase in compensatory time (for management employees) and overtime (for union employees). (*id.)* CPB also opines that "effective management needs to analyze the cause of overtime …" (3219). Both of these adjustments to overtime should be rejected.

The Company's Accounting Panel explained that employees (for the most part) receive increases annually and overtime therefore increases at the same rate of salary increase. (1409-1410). They also described the fact that much of the overtime associated with storm costs were normalized out of the rate year. (1410). Finally, as to CPB's suggestion that the additional work force will decrease the level of overtime, the Accounting Panel noted that overtime and compensatory pay will be required at some level. (*id.)* More importantly, they remind CPB that the additional personnel proposed in this rate filing are intended to address new initiatives and programs, not to decrease overtime levels. (*id.)*

On cross, the Panel explained that compensatory overtime was a necessary cost of doing business and that it places entry or low level management employees "on par" with weekly employees. (1496). Additionally, they explained that new employees take "a while" to get up to speed and that the Company is losing significant numbers of long-term employees and replacing them with people with very little experience. (1497-1498). The overtime level is not expected

to decrease in the rate year and the Company's forecast should be included in the revenue requirement.

CPB's adjustment to overtime was made without its making any inquiry as to the steps the Company takes to analyze and review overtime. (3316; Exh. 216). In fact, CPB admitted in response to a Company discovery request that it did not know what steps the Company takes to analyze overtime. (Exh. 216).

There is no basis for CPB's adjustment and it should therefore be rejected.

4. <u>Shared Services and Other Open Position Adjustment</u>

CPB recommends that the Company's labor normalization of $3.37 million be reduced by $2.46 million to $912,000. (3215). They claim that the only "costs that could reasonably be considered to be justified are the shared services and finance and auditing costs." *(id.)* Without explanation, they allow 75 percent of the amount requested for Shared Services and Finance and removed all other normalizations. (*id.)*

In rebuttal, the Company's Accounting Panel addressed this adjustment. (1407). They explained that any vacancies that occurred in the historic year are reflected in the costs for that year. (*id.)* Normalizations are the costs for the vacancies that are expected to be filled during the rate year. (*id.)*

CPB has not demonstrated that the Company will not fill these vacancies nor have they shown that the Company is not addressing these vacancies. As such, they have not provided any justification for their adjustment. CPB also has not explained why the shared service and finance and auditing normalization should be limited to 75 percent.

CPB summarily dismisses most of the Company's labor normalizations, claiming that they have not been justified by the Company. CPB obviously missed the several discovery

requests that Staff made regarding these normalizations. (Exh. 240, pp. 61-62, 78-79; Exh. 244). The Company provided detail as to the open positions, what they are and when they originally opened.

Having failed to support its $2.4 million adjustment for normalizing salaries for positions the Company intends to fill, CPB proposed adjustment should be rejected.

5. <u>Management Compensation</u>

a) <u>Employee Welfare Expenses</u>

Company witness Reyes, the Director of Benefits and Compensation, presented the Company's forecast of employee welfare expenses, including the costs of: health insurance; group life insurance; and executive compensation. (1116-1131;1134-1150). Adjustments to the Company's health insurance costs and stock-based deferred compensation plan have been recommended by Staff, and CPB has proposed adjustments to the Company's group life insurance costs and Variable Pay Plan for management employees. For the reasons discussed herein, these adjustments should be rejected.

(i) <u>Health Insurance Costs</u>

Staff bases its forecast of health insurance costs on the Company's latest known health insurance costs for 2008, escalated by a general inflation factor of 1.98 percent to estimate health care costs for calendar year 2009. (3579). Staff then combines nine months of 2008 costs and three months of 2009 costs to forecast the rate year level of the Company's health insurance costs. (3579). Notably, Staff does not disagree with the Company's assertion that health care costs are rising, and will continue to rise, at a rate greater than the general inflation rate. (1122). Nevertheless, Staff argues that the general inflation factor should be used because health care costs are part of the pool of costs upon which the general inflation factor is derived. (3578).

Staff also explains that use of the general inflation factor to forecast the increase in health care costs is consistent with the Commission's practice adopted in a 1985 rate case decision. (3578).

This Commission practice should not be applied to current health care costs. While it may have been appropriate at one time to apply a general inflation factor for health care costs, such application is no longer justifiable.

The recent documented history of increased health care cost trending is significantly above the level of general inflation.

As Mr. Reyes makes clear, health insurance costs for hospital, medical, and prescription drugs are expected to continue to rise at a rate approximately four times greater than the CPI inflation rate. (1122; 1137-1142). No party introduced evidence that this trend will change during the rate period. (1121-1122). Accordingly, this trend warrants the utilization of a more realistic inflation factor for health care costs.

As Mr. Reyes explained, departure from the general escalation approach is appropriate in certain circumstances, including, such as here, when such a "pool" approach significantly understates the probable increase of the expense. (1137-1138). For example, the Company's actual health care claims experience for hospital and medical care costs in the first eight months of 2007 increased by $5.2 million over the same period in 2006 (8.0 percent annualized), and neither the Company nor its insurance carriers see any reason why this trend will not continue in the rate year. (1138). In fact, the contract rates for three of the Company's major HMO plans will be increasing on average by approximately 16 percent from 2007 to 2008. (1138).

It bears emphasis that the Company does not propose use of this higher inflation factor for all employee welfare expenses. Rather, to reflect more accurately the magnitude of increases in employee welfare costs, the Company proposes using different escalation factors for different

types of employee welfare expenses. First, a labor factor of 6.39 percent is used to escalate employee welfare costs that are a function of salaries and wages. (1121). Second, a non-labor factor of 4.7 percent is used to escalate employee welfare costs that are unrelated to salaries and wages (1121). The projected health care cost trend rates of 8.0 percent and 9.5 percent are used only to escalate hospital/medical care costs and prescription drug costs, respectively. (1121-1122). The rate of increases for health care costs were estimated based upon the medical inflation trends as reported by Buck Consultants and projected changes provided by the Company's health care carriers. (1122).

Further, it bears mention that in forecasting the level of operating expenses, the Company did not apply the general inflation factor to all costs in the "pool," but, in fact, forecasted no change or a decrease for certain costs. That is because certain costs are by their very nature fixed and/or decreasing (*e.g.*, carrying costs on the East River Repowering Project, uncollectible costs and property tax rates). Exhibit 84, Schedule 9 lists electric cost elements that were escalated using a general inflation factor. This Exhibit shows that only 38% of costs excluding purchased power were escalated using a general escalation rate (13% including purchased power).

The Company's escalation factors for health care costs are supported by numerous studies and surveys indicating that these costs will continue to increase in the future at a rate higher than the general inflation rate (1122; 1140-1142). For example, the 12th Annual National Business Group on Health/Watson Wyatt Survey Report 2007 indicates that health care costs increased by 8.5 percent in 2005; 8.0 percent in 2006; and are projected to increase by 8.0 percent for 2007 and 2008. (1138-1139). National surveys prepared by Towers Perrin, Buck Consultants, Kaiser Family Foundation, and other well-respected organizations also conclude that year after year, health care costs have seen increases above and beyond the general inflation

level and that this upward trend is expected to continue. (1140-1142). The use of the general inflation factor does not result in a reasonably accurate estimate of the costs, understates the probable increases in health care costs and, therefore, understates the revenue requirement. (1139). Simply put, the application of the general inflation escalation factor does not produce a reasonable forecast for health care costs and should not be used in forecasting these expenses for the rate year. (1139).

(ii) <u>Group Life Insurance</u>

For management employees, the Company provides group term life insurance equal to their base annual salary. (1124). The Company provides $30,000 of group term life insurance for members of Local 1-2 and Local 3 in accordance with the collective bargaining agreements. (1124). CPB asserts that the Company ignored the dividends received from its insurance provider, MetLife, in stating its historic year group life insurance costs and therefore recommends an adjustment to the Company's projected revenue requirement. (3224-3225). CPB's assertion is incorrect.

First, Mr. Reyes explained that the Company did not ignore the dividends received from MetLife in calculating its historic-year premium costs because these dividends were not a credit against that year's payments. (1148). Second, irrespective of the timing of a dividend, Mr. Reyes explained that dividends are not an annual certainty and, in any given year, the Company could just as well be required to make an additional payment to MetLife. (1148; 1163-1165). That is, annually, MetLife performs a review of the actual claims experience and depending upon the number of claims paid, dividends may or may not be due to the Company. (1148-1149). If the claims are greater than MetLife forecasted, then there is no dividend; rather the Company incurs additional costs for group life insurance. (1149). For example, in 2004, the

Company was required to pay MetLife the full premium plus some additional costs, since the claims experience was greater than projected by MetLife. (1148-1149; Exh. 66). As such, the Company's prediction of group life insurance costs is based on the expected rate-year premiums as supplied by the Company's insurance carrier. (1162-1163). Since there is no certainty that a refund will be received or that additional costs will be paid in any given year, it would be inappropriate to include an amount representing an estimate of either a refund or additional payment in the projected expense. Accordingly, CPB's adjustment should be rejected.

(iii) <u>Executive and Management Compensation</u>

Staff recommended an adjustment disallowing the Company's stock-based deferred compensation plan. CPB recommends disallowance of the costs of the Company's Variable Pay Plan for management employees. Both adjustments should be rejected as these plans are an integral part of management employee compensation and thus, a legitimate business expense. These plans are in line with the management compensation plans of other utilities and provide benefits to the Company's customers.

(a) Deferred Compensation – Stock-Based Plans

As Mr. Reyes explained, deferred compensation in the form of stock options is part of the annual compensation package available to the Company's officers and management employees. (1142). Staff recommended disallowing the Company's recovery of all the costs of stock-based deferred compensation on the ground that "Commission policy" does not permit the recovery of incentive payments from customers. (3606-3607). Although the Commission has denied rate recovery of certain types of incentive compensation plans in cases involving other utilities, these are fact-specific determinations. The Company is unaware of any Commission policy prohibiting rate recovery of such plans. In fact, the Commission has permitted rate recovery of

incentive compensation plans in approving various rate settlement agreements, even rejecting an intervenor argument that the costs of a Con Edison management incentive compensation plan should be disallowed because there was no "persuasive basis for disallowing what is a legitimate business expenditure."[138]

The Company submits that its stock-based plans should be viewed as an integral part of the annual compensation package, consisting of cash and equity-based compensation, which the Company offers to its officers and management employees. (1142). Even CPB agrees that the costs of officer compensation are an expense recoverable from customers. (3328-3329). Although the plans reward high levels of performance, the stock options are also intended to attract and retain top talent critical to the Company's long-term success. (1142). As such, the costs of these plans are a legitimate business expense.[139]

The Company's compensation package, which reflects the nature of the Company's business and its gross revenue (1142) is also designed to be competitive with median levels of compensation provided by a peer group of companies even though Con Edison's officers and management group are disadvantaged by the high cost of living in the New York City area. (1130).

In 2007, based upon the recommendations of the Board's independent compensation consultant Mercer Human Resources Consulting, the Company established an industry peer group of 20 publicly-traded utilities of comparable size and scope to the Company for the purpose of evaluating and determining executive compensation levels. The 2007 peer group includes the following companies: Ameren Corporation, American Electric Power Company

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[138] Case 91-E-0462, Consolidated Edison Company of New York, Inc. – Electric Rates, *Opinion and Order Adopting Settlement*, Op. No. 92-8 (issued April 14, 1992), 32 NY PSC 441, 488.

[139] In fact, the Company submits that the costs of its annual bonuses to executives, another part of the compensation package to officers, should be recoverable from customers. Consistent with prior practice, the Company has, however, elected to not seek recovery of these bonuses as part of this rate request. (3814).

Inc., CenterPoint Energy Inc., Constellation Energy Group Inc., Dominion Resources Inc., DTE Energy Company, Duke Energy Corporation, Edison International, Entergy Corporation, Exelon Corporation, First Energy Corporation, FPL Group Inc., NiSource Inc., Pepco Holdings Inc., PG&E Corporation, PPL Corporation, Progress Energy Inc., Sempra Energy, The Southern Company Inc., and Xcel Energy Inc (1143). Internal compensation surveys of other utilities also were used to determine annual compensation increases for management employees. (1143). The costs of the Company's stock-based plans are an appropriate, reasonable and legitimate business expense and should be recoverable as a cost of providing service. (1143-1144).

(iv) <u>Variable Pay Plan</u>

As is true of the Company's deferred compensation plan, the Variable Pay Plan is an essential part of the compensation package awarded to eligible management employees. (1145-1146). Both merit increases and variable pay awards are elements of an eligible management employee's compensation and, awarded together, encourage and reward the highest level of employee performance and enable the Company to compete successfully for talent. (1146). In fact, if variable pay were not a component of compensation for eligible management employees, the level of merit increases would be higher than they are at present. (1146). As Mr. Reyes noted, at the time the Variable Pay Plan was adopted, the Company actually decreased the percentage of merit pay normally given to employees. (1146).

CPB has recommended disallowance of all of the costs of the Company's Variable Pay Plan for non-officer management employees. (3221-3223). According to CPB, the Company did not provide requested documentation regarding the program or establish that the costs of the program should be borne by customers. (3223). This is not the case.

During the discovery phase of this proceeding, in response to a CPB request, the Company provided CPB with a description of the Variable Pay Plan fully responsive to CPB's request. (Exh. 65). And, indeed, as CPB witness Schultz conceded during cross-examination, after receiving the Company's response, the CPB never requested any further information regarding the Variable Pay Plan from the Company. (3354). As such, the Company had no reason to believe that it had not complied with the CPB's request for documentation regarding the program. (1160-1161).

CPB also asserts that the Variable Pay Plan provides awards to management employees with at least satisfactory performance and that variable pay should be awarded only for performance over and above that which is expected of an employee and which results in shareholder and ratepayer benefits. (3222). As Mr. Reyes explained, although management employees with at least satisfactory performance are eligible to receive a variable pay award, these employees are not automatically entitled to the full amount of the variable pay award (1156). Instead, the Variable Pay Plan recognizes that managers should have discretion to encourage employee performance on a higher level on a case-by-case basis. (1144-1145).

CPB also asserts that the Company failed to demonstrate that customers benefit from the Variable Pay Plan. (3223). Customers do, of course, benefit from the performance of management employees. (1145-1146). Innovative and more productive ways of doing business, lower financing costs than would otherwise be obtained, the ability to fund infrastructure improvements in a reasonable manner, and the ability to attract and retain highly qualified and motivated employees are illustrative of customer benefits.[140] (1146).

[140] Indeed, the Variable Pay Program is consistent with the Company's vision and teamwork and recognizes that all individual employees contribute to the Company's achieving its operating objectives.

It would, therefore, be arbitrary for the Commission to retain for the customer the benefits that the Variable Pay Program has provided to them while at the same time precluding recovery by the Company in rates of costs incurred by the Company that have contributed to achieving these benefits. (1146-1147). The costs of the program are an important and proven part of the cost of providing quality service to customers at reasonable rates and should be recovered like any other cost of service. (1147). Additionally, Variable Pay is a form of compensation that supports a high level of performance without increasing the fixed costs of base pay.

The Company's Variable Pay Program is, moreover, comparable to programs offered by other utilities. Mr. Reyes explained that Con Edison conducted a compensation survey of other utilities to see if they offer a variable pay plan and if so, the projected increase. (1147). Some of the utilities that were contacted were NSTAR, Northeast Utilities, Public Service Electric & Gas, Keyspan Energy, Progress Energy Service Company, Entergy, and Edison International. (1147). The survey indicates that these other utilities actually offer employees a greater proportion of their compensation in the form of variable pay than Con Edison does under its plan. (1147).

For all of the above reasons, CPB's proposed disallowance of the costs of the Variable Play Plan should be rejected.

E. <u>General Escalation</u>

The Company applied a general escalation rate to certain O&M costs in the filing.[141] The categories of escalated costs are listed on Exhibit 84. (Exh. 84, Sch. 9). The Company derived the 4.7 percent escalation rate by which these costs were escalated by using the projected increase in the Gross Domestic Product ("GDP") price deflator. (1317). As of the filing date,

[141] As discussed above, the general escalation rate was not used for certain costs, including health care costs.

the most recent GDP had been published on January 31, 2007 and forecasts for future periods were taken from the Blue Chip Economic Indicators dated January 10, 2007. (*id.)* For the quarter ended March 31, 2009 (the end of the rate year), the Blue Chip quarterly rate, which was projected at 2.1 percent annually, was applied from January 1, 2007 through March 31, 2009. (*id.)* At the time of update, the Company reviewed its assumptions and the numbers had not changed significantly.

Staff did not adjust this inflation factor. Staff did remove inflation adjustments for programs that they recommended be removed from the revenue requirement. These adjustments totaled $814,000. (3607). To the extent that Staff's recommendations regarding these programs are rejected and these programs are reflected in the revenue requirement, then the inflation adjustment should be included in the revenue requirement as well.

CPB claims that because certain costs escalate from year to year, applying an escalation factor is inappropriate. They make three adjustments to the escalation factor in the areas of interference ($3.544 million),[142] injuries and damages ($1.8 million) and other ($2.237 million). (3284-3285). CPB has provided no justification for any of these adjustments. (*id.)* The testimony addressing this adjustment is barely more than one page and seems to imply that there "may" be a double count if the projected or the forecast costs already include inflation. (*id.)*

CPB's rationale for removing the escalation for injuries and damages is specious. (3285). The CPB Panel states that injuries and damages is an expense like materials and supplies and that no justification exists for escalating the expense. (*id.)* This reasoning is puzzling. The Company's Accounting Panel explained in rebuttal that this category represents the historic three-year average of actual payments. (1436). More importantly, on cross-

[142] As discussed, in the interference portion of this brief, CPB's adjustment is moot based on the Company's update.

examination, the Company's Accounting Panel explained that Staff has historically used a three year average of actual claims payments. (1535). "It's been the commission's practice, or at least the Staff's practice, to use an average of actual claims paid rather than the accrual that's booked by the accounting area each year." *(id.)* CPB has shown no reason to deviate from a practice that has been consistently applied for a number of years and to various utilities in the state. (1536). This adjustment should be rejected.

The Company's Accounting Panel testified that most program changes are developed without any escalation so applying this factor is proper and is not a double count. (1437). CPB makes no demonstration that there indeed was any double count but rather speculates that it may have occurred. As shown above, the injuries and damages category needs to be adjusted for inflation. Without the adjustment, the rate year has a built-in shortfall. Similarly, all other costs should also reflect inflation. CPB's arbitrary removal of the entire amount of costs that must be escalated is completely unsupported. In light of the record evidence, its purported "double count" rationale remains rank speculation. As such, this adjustment should be rejected.

As explained in this section, all programs should be escalated as calculated by the Company.

F. <u>Labor Escalation</u>

The Company utilized a 6.39 percent labor factor to escalate the historic test year labor expense level to the rate year. The rate year labor forecast included a "one percent" annual productivity savings, calculated from January 2007[143] to March 2009. (1318). Without the annual productivity reduction, the labor factor would have been 8.36 percent. As such, the

[143] The transcript at p. 1318 states 2006. The correct reference is 2007.

calculation of the productivity savings for the Rate Year is actually 1.97 percent. (Exh. 85, Schedule 2, p. 1 of 4).

The Company applied the 6.39 labor factor to the 2006 actual average wages and salaries of Weekly and Management employees, including increases for Weekly employees pursuant to negotiated labor agreements and a merit increase for Management employees. The Company also applied the 6.39 labor factor to the actual amount of salaries and wages for other than straight time payrolls (*e.g.*, weekly premium and overtime payrolls). (1319-1320).

The one percent per annum productivity factor utilized by the Company has been reflected in numerous rate plans adopted by the Commission. (1414). In that context, it has long been accepted as a proxy for the level of customer benefits achieved from productivity achieved during the period for which rates are set. (3694-3695). To the extent a utility achieves a higher level of productivity it has been allowed to retain those benefits between rate cases (subject to earnings sharing provisions, where applicable), and customers would receive these higher productivity benefits on a permanent basis the next time rates are set. As explained by Company witness Kane, "productivity enhancements are achieved over time, not instantaneously, and not necessarily through labor savings. As savings are actually realized, customers will reap the benefits in future rate case filings as these savings will be reflected in the historic year." (1415).

Although the Company is not legally required to reflect a productivity factor in its rate filings, according to Company witness Kane, the imputation of productivity adjustments has been standard practice for most of the 31 years he has been working in the utility industry (1525). The Company elected to follow this long-standing practice in this case.

1. Staff's Position

Staff did not object to or otherwise propose any adjustments to the Company's one percent productivity adjustment. Staff witness Scherer testified that the one percent productivity adjustment has been in place during the 20 years he has been with the Department of Public Service. (3676).

In response to cross-examination by Local 1-2, Mr. Scherer further explained the Commission's policy on the productivity imputation as

> a surrogate for specific adjustments of overall productivity gains. It's not intended to equate directly to either reduction of employee levels or denial of recovery of pension or other benefit costs. So it's really simply nothing more than a surrogate for expected overall productivity gains, it could come from many, many forms. And that's the Commission's traditional applications of this adjustment and that's the intent and purpose of it (3680).[144]

On cross-examination, in response to a question presented by NYC as to whether all productivity from the one percent productivity adjustment is assumed to be labor, Mr. Scherer responded that

> [i]t's my understanding that the Commission's traditional application is nothing more than a proxy for measurement of expected productivity gains. There is no prejudgment as to where those gains may come from, it could be labor, it could be any other cost the Company incurs that they find a way to do more efficiently. It's not necessary (sic) a function of labor. It can be labor derived, but it's not necessarily derived by labor (3694-3695).

2. NYC's Proposal

NYC, through its witness Arnett, has recommended that the productivity adjustment be increased from one percent to three percent of Company labor per year. (4497). Mr. Arnett based this recommendation on the "extraordinary levels of new capital projects and O&M

[144] Staff witness Scherer was referencing a recent Commission decision in Case Nos. 06-E-1433 and 06-E-1547, Orange and Rockland Temporary Electric Rates, Order Setting Permanent Rates, Reconciling Overpayments During Temporary Rate Period, and Establishing Disposition of Property Tax Refunds, Issued and Effective October 18, 2007, pp. 18-19.

programs that the utility has undertaken over the past few years and is proposing to continue and expand for the new rate plan." (4491). Mr. Arnett testified that he reviewed new capital projects and O&M programs and indicated those he believes present a productivity opportunity. (4492-4493).

NYC's recommended adjustment is based on hypothetical savings and inadequate analyses. To the extent analyses were conducted they were based on flawed assumptions. As such, NYC's recommendation for a three percent productivity adjustment based on "potential productivity" is punitive and should be rejected.

a) Capital and O&M Projects and Programs

On cross-examination, Mr. Arnett confirmed that the recommendation for a three percent productivity adjustment was based on the magnitude (*emphasis added*) of the Company's proposed capital and O&M programs. (4511-4512). However, concerning the proposed capital spending, Mr. Arnett admitted that only $200 million of the Company's $1.3 billion in proposed capital spending, or less than 15 percent, had any potential for productivity improvements. He stated that "there are large expenditures, projects, that we didn't see a potential for productivity gains emanating from things like substations." (4512). As such, any suggestion that the projected level of the Company's proposed capital spending mandates additional productivity savings lack merit.

In terms of NYC's analysis, Mr. Arnett admitted that he made no comparison of potential productivity savings for capital programs in the instant proceeding with programs proposed by the Company in its last rate filing. (4512-4513). In a Company interrogatory, Mr. Arnett was asked whether he had calculated the incremental cost savings of the numerous programs that had been identified by Mr. Arnett as representing productivity improvement opportunities. In

response, Mr. Arnett indicated that he had not calculated the incremental cost savings. (Exh. 298). During cross-examination, Mr. Arnett confirmed, on two separate occasions, that no incremental cost savings were calculated. (4515-4516). In fact, the record in this proceeding is devoid of calculations of incremental cost savings for <u>any</u> of the programs identified by Mr. Arnett on Exhibit 293 as providing potential productivity opportunities.

And finally, Mr. Arnett admitted that the proposed projects for which there are potential productivity savings would not necessarily be in service for the entire rate year. (4513). As discussed below, Mr. Arnett's references to potential productivity savings from projects commenced during the 2005 Rate Plan should not form the basis for a higher productivity adjustment in setting rates commencing April 1, 2008.

b) <u>Double Counting Of Productivity</u>

In Exhibit 294, the Company explained that for any O&M program proposed by the Company that was expected to reduce O&M costs for a particular activity, the RY1 revenue requirement reflected such reduced costs for that activity. (Exh. 294, Schedule 10). Also, O&M expenses for RY2 and 3 of the proposed three year plan reflect any reduced RY1 costs (except as specifically excluded) reduced by an additional imputed one percent productivity adjustment for each year. *(id.)* The majority of the programs referenced in this interrogatory are included among those for which Mr. Arnett uses as the basis for his three percent productivity proxy. However, Mr. Arnett does not adjust his calculation in any manner to take these reductions into consideration, thereby engaging in a double-counting of productivity for a myriad of projects.

The Company's revenue requirement calculation was reduced for expected O&M savings for these projects, and then, without adjustment for these project-specific savings, the Company applied the one percent productivity adjustment to its total labor expenses. The application of an

additional two percent productivity savings adjustment by Mr. Arnett on top of the productivity savings already reflected by the Company results is excessive. Since any productivity from these programs has therefore been accounted for and further reduced by the Company's productivity adjustment, NYC's proposal to impose additional, hypothetical productivity for these projects is totally unwarranted.

NYC's proposal is further flawed in that many of the projects that appear on the pages referenced in Exhibit 294 are, in fact, projects that Mr. Arnett identified as having no potential productivity opportunities.

c) <u>Six Percent Productivity Adjustment</u>

As discussed above, the Company calculated its "one percent" productivity adjustment for a 27-month period that includes the linking period. As such, the actual annual productivity adjustment applied by the Company is 1.97 percent. For RY1, Mr. Arnett simply multiplied the Company's productivity factor by two and then further reduced the Company labor revenue requirement by that amount (Exh. 296). He applied similar processes for RYs 2 and 3. (Exh. 296). As such, the productivity adjustment factor applied by Mr. Arnett is not three percent as he testified (4497) but is nearly six percent (5.91 percent). On cross-examination, Mr. Arnett acknowledged that his productivity calculation would result in a productivity adjustment of six percent being imputed to the Company. (4529).

Mr. Arnett's resultant productivity adjustment is wholly arbitrary and contrary to Commission precedent. As testified by Local 1-2's Mr. Koda,

> Mr. Arnett has not provided the algorithms with which he concluded that a 3% productivity adjustment is appropriate in this proceeding. The 3% appears to be a guesstimate made without any quantification and comparison of prior productivities, real or imagined. What productivities are already embedded in present operations of the Company? Why is a 3% adjustment recommended rather than a 5% or, for that matter, a minus 1% adjustment? (5047).

Mr. Arnett has neither provided a basis for reasonably calculating his proposed productivity adjustment nor established why the Commission should deviate from its historic practice of giving utilities the incentive to achieve and retain such higher efficiencies between rate cases to the benefit of its customers.

d) <u>The Company's Prior Rate Plan</u>

Mr. Arnett also refers to spending on capital projects and O&M programs the Company has undertaken over the past few years (4491) and spending levels under the current rate plan (4513) as a basis for applying a three percent productivity factor in the instant proceeding. Such a proposal is patently unreasonable and contrary to the Commission's established rate making practices.

For example, Mr. Arnett agreed that the Company's filing in its prior rate proceeding (Case No. 04-E-0572) reflected a one percent productivity adjustment. (4525). Exhibit __(HLL-5), Schedule 2, included as part of the Company's prefiled exhibits in Case 04-E-0572, shows the development of the productivity adjustment adopted in that case. The Company's current rate filing was prepared using the same methodology as adopted in that case. Although not noted explicitly in the 2005 Rate Plan, there is no basis for assuming that the 2005 Rate Plan did not reflect this one-percent productivity adjustment, which was unchallenged by any party.

Accordingly, the Company's customers currently benefit from a productivity adjustment and will continue to do so through the end of the 2005 Rate Plan. And even though that productivity factor was intended to capture efficiencies achieved during that rate period, as noted above, the Company has, on a voluntary basis, calculated its one percent productivity factor for the rate year to include the linking period, which results in customers receiving recognition in

future rates of productivity achieved during a portion of the 2005 Rate Plan in addition to the productivity adjustment already reflected in current rates.

Mr. Arnett acknowledged that any productivity achieved by the Company through December 31, 2006 would be captured in the Company's calculation of the historic year, upon which the rate year revenue requirement is based. (4514). While Mr. Arnett speculates that there may be additional, post-2006, productivity savings achieved under the current plan that are not reflected in the rate year calculation (4514-4515), there is no basis for considering such productivity in establishing future rates.[145] Rates have been fixed by the Commission for the period of the current rate plan, including reflecting the productivity adjustment that the Commission deemed appropriate. Moreover, consistent with Commission precedent, the rate plan contemplates that to the extent the Company achieves more or less productivity than the amount imputed in rates, the Company would be at risk or reward for such amounts. To adjust future rates in the context of a higher productivity adjustment to capture past productivity would clearly constitute retroactive ratemaking.

e) <u>Company Work Forces</u>

Con Edison is experiencing retirements and attrition in both union and management positions at a rate that requires the addition of over 1000 new employees per year. (*see* 115-117; 4517 Exh. 3). In fact, the Company is proposing to hire approximately 1400 new employees in 2008. (111; 4517, Exh. 3). By the year 2010, the Company projects that more than half of its work force will have less than ten years worth of experience. (Exh. 295; 4518).

[145] The Company would note that Mr. Arnett did not conduct for the past programs even the superficial analysis conducted for the proposed programs.

During cross-examination, Mr. Arnett testified that he "looked at changes in head count, hiring and attrition" when asked if he considered the Company's recent firing[146] (*i.e.*, sic) and attrition rates in conducting his productivity analysis. (4516-17). However, Mr. Arnett was unaware of the fact that by the year 2010 more than half of the Company's work force will have less than ten years of experience. (4518). He was unaware of the need for training for new employees and the need to hire additional trainers. (4517-4518). While he admitted that a new hire would require more training than a more experienced employee (4520), he did not consider, for example, that Company work practices might require a three-person crew rather than a two-person crew when less experienced employees are involved in certain tasks. (4521). This failure to consider the inefficiencies associated with a rapidly changing work force is another material flaw in Mr. Arnett's analysis.

While Mr. Arnett may have "looked at" hiring and attrition rates, it is clear from his cross-examination that several extremely important factors were not given sufficient attention. As demonstrated above, Company hiring and attrition rates will have a significant impact on the Company and any immediate realization of productivity. Without the appropriate consideration of the impact of new employees, additional workers and additional trainers and training, NYC's proposal to increase the productivity adjustment is further flawed.

f) <u>Productivity Savings - Conclusion</u>

For all of the foregoing reasons, there is no reasonable basis for the Commission to deviate from its historic practice in this case and subject the Company to imputed productivity multiples of that historically and currently applied to the Company and to other utilities.

[146] Although the transcript reads "firing," the question posed asked "hiring."

G. Reserve Accounting For Storms And ERRP Major Maintenance

In addition to the reconciliations discussed in section VII, the Company also proposed that reserve accounting be established for two categories of costs – storms and ERRP Major Maintenance.

1. Storm Reserve

The Company normalized the historic year expenditures so that only $8 million is included in the rate year for storm costs. (1363-1364).[147] The Company determined that the $8 million would be the proper amount by considering two categories of storm related costs – storm mobilizations and storm reserve.

The Company calculated that it would need approximately $2.4 million in storm mobilization costs, which are the incremental overtime incurred when employees are called into work when storm activity is forecast. (1364). These employees are brought in to work so that they are ready to respond in the event that the storm causes damages to Company facilities and as a result, service is interrupted. (*id.)* This figure represents an increased level of mobilization undertaken after the storm events of 2006. (*id.)*

The remaining $5.6 million of this storm cost is to fund a storm reserve for significant storm activity of Category 2 or higher storm events. (*id.)* This reserve would be available to fund costs of $1.5 million per year for two Category 2 storms (allowing for $750,000 per storm), $1.1 million per year for a Category 3A storm and $3.0 million per year for a Category 3B storm.[148] The Company considered all of the storms within the last 15 years and developed a corresponding amount. For example, for Category 2 storms, in the last 15 years, there have been

[147] As explained earlier, the Company expended over $24 million in storm costs in the historic year.

[148] Over the last 15 years, on average, the Company has experienced two Category 2 storms (at a cost of $750,000 per storm) annually, one category 3A storm (at a cost of $2.2 million per storm) every two years and one Category 3B storm (at a cost of $9 million) every three years. (1364-1365).

30 of these storms at a cost of $700,000 per event. (1429). This reserve would allow the Company funding for two events, which is the annual average. (1429)

In addition, the Company proposes to true-up these costs at the end of either one-year or a three-year plan. A regulatory asset would be created if the spending level does not reach the $8 million and a regulatory liability would be created if the spending were greater than $8 million. (1366). This, of course, is dependent on the number and level of storms, which is completely out of the Company's control. (1428).

The Commission has authorized storm reserves for other New York State utilities, including National Grid, New York State Electric and Gas, and Orange and Rockland Utilities. (1366).

No party suggested that the storm reserve not be established. However, CPB suggested that the reserve be funded at $5 million, not the $8 million requested by the Company. (3282-3284). CPB makes its adjustment claiming that the Company's discovery responses only showed three years in 15 years where the costs for storms exceeded $5 million. (3283).[149]

In rebuttal, the Company's Accounting Panel explained that in 2006, the Company incurred nearly $25 million in storm costs, well above the $8 million requested in the reserve. (1428). The Panel also reiterated the derivation of the $8 million, noting that it was based on the average number of Category 2 and 3 storms and their associated costs over the last 15 years. Again, this is a cost well out of the Company's control. (1428-1429).

CPB has not shown that the Company's requested level of storm reserve is improper but rather they believe the cost is too high. Unfortunately, recent 2006 experience demonstrates that the costs can well exceed what is in the reserve. CPB has not demonstrated that the Company

[149] They also suggest a "tracking account," but do not explain it or the mechanism they recommend. (3284). The Company believes that the reserve account would have the same effect as a "tracking account."

will not spend the amount requested in the reserve nor have they justified why the mechanism for adjusting the costs at the end is unworkable. Nor has CPB explained why their $5 million is closer to the amount that the Company will reasonably spend. As a result, the Commission should approve the Company's proposal

2. <u>ERRP Maintenance Reserve</u>

Under the 2005 Rate Plan, the Company was allowed to collect approximately $7.5 million annually in rates for maintenance expenses associated with ERRP. (1367). The Joint Proposal reflects that spending for ERRP maintenance would be collected on a levelized basis, even though it the costs may not be incurred ratably. (*id.*; 1425; 942). And as expected, these expenses have not been incurred ratably. As a result, the Company anticipates that it will have approximately $8.7 million accrued, but unexpended, for major maintenance at the end of the rate plan. (1368).

The Company proposed to carry the credit balance forward to fund a permanent maintenance reserve and defer additional maintenance cost recoveries of $7.5 million per year to this account. (*id.)* Actual expenses would be charged to this account as incurred. (*id.)*

As to the maintenance schedule, the Company expects to spend a total of $24.1 million over the next three years on ERRP major maintenance. (1369). Absent this reserve and holding the funds from the current agreement, the Company will not have sufficient funding in rates to meet the maintenance schedule. (*id.)*

Staff's Accounting Panel adjusts the Company's proposal, returning the $8.7 million to customers in the rate year. Staff agrees that the $7.5 million should continue to be imputed in rates for this work but claims that the Company has failed to show how the reserve accounting would benefit customers and due to the magnitude of the rate request, the $8.7 million should be

returned to customers in the rate year. (3580-3582). Staff also claims that the Company can reasonably estimate the level of spending and that it has control over the timing of these maintenance expenses. (*id.)*

In rebuttal testimony, the Electric Production Panel explains that the major maintenance on this equipment is based on specific operating intervals – 12,000 hours for a combustion inspection, 24,000 hours for a hot gas path inspection, and 48,000 hours for a major inspection – but the "actual timing of when these durations are achieved is variable." (940). Moreover, the Electric Production Panel notes that some factors impacting the timing include weather, unit trips and other unpredictable events. (*id.)* Staff's assertion that the Company controls the timing of the outages misunderstands the operation of these units.

The Company's Accounting Panel further explained that absent the establishment of this reserve, that the Company reserved its right to retain these unexpended funds. The Accounting Panel noted "there are no provisions in the current rate plan to either pass back or surcharge to customers any variation in spending for the ERRP maintenance." (1427; 1505-1508). *(id.)* That is, like numerous other O&M expenses, the existing rate plan did not establish any reconciliation for these expenditures. Notwithstanding, the Company proposed in this case to forgo its right to retain these funds in the context of establishing a reserve. (1427).

Accordingly, Staff's criticism that customers do not benefit from the Company's proposal to establish a reserve is in error. As a result of the Company's proposal, customers are not being asked to pay an additional $8.7 million that the Company could use for other projects or costs. Rather this funding is being set aside to help defray future costs for this one particular item. If this set aside does not occur, rates would need to be increased to meet this spending

level. Equally important, Staff's proposal for this refund would constitute retroactive ratemaking.

The Company's proposal treats customers fairly. Only the actual maintenance expenses will be funded by customers. Consequently, the Company's request for deferral accounting for the ERRP maintenance expenses should be approved.

H. <u>Fuel Costs</u>

Company witness Holtman, Director of Electricity Supply, testified as to the Company's projected electricity supply costs in the rate year and beyond. Mr. Holtman explained Con Edison's supply purchasing history and the Company's supply cost projections (some portion of which is confidential). (1228-1241).

Mr. Holtman explained that the Company seeks the lowest reasonable cost (including mitigating volatility) for its customers, subject to reliability and contractual constraints. (1228). The Company accomplishes these objectives by aggressively pursuing commercial opportunities, such as favorable contract restructuring or extensions. *(id.)* The Company also aggressively pursues market structure changes that are beneficial to its customers by actively participating in the NYISO and at FERC. (*id.)* Mr. Holtman described the Company's efforts to mitigate volatility through hedging. (1233-1235).

The Company's projections for supply costs in the rate year were provided in Exhibit 79 and described in great detail in Mr. Holtman's testimony. (Exh. 79; 1235-1241).

No party commented or made adjustments to these comprehensive projections. As such, Mr. Holtman's projections should be adopted.

The Commission should reject NYC's proposal that the Company be required to engage in integrated resource planning. The Company would note that a number of issues that stem

from NYC's proposal, already are being considered in a separate proceeding.[150] In particular, NYC requests in this proceeding that the Commission order Con Edison to take certain actions with respect to potential sources of generation energy supply, such as central generation and transmission. (4978). The Commission's IRP proceeding will consider the extent to which Con Edison needs to be involved in these issues, beyond its involvement as a transmission owner in the NYISO Comprehensive Reliability Planning Process ("CRPP"). NYC has not proffered any evidence demonstrating a need to have these issues considered in this proceeding. Indeed, when the Company asked NYC in an interrogatory to explain its position in more detail, including in particular whether the NYC has raised these issues at the NYISO, NYC replied as follows:

> The City objects to this interrogatory as it does not relate to the subject matter of this proceeding. This is a proceeding to determine the rates, charges, rules and regulations of Con Edison's electric operations. Inasmuch as this interrogatory does not seek information from the City on its positions related to Con Edison's electric operations or is otherwise relevant to this proceeding, the City objects.

Con Edison concurs. All of the issues raised by NYC are outside the scope of this proceeding and are more properly considered in either the Commission's IRP proceeding or as part of the NYISO's CRPP. (1250-1252).

For the same reasons, the Commission should reject NYC's request (4982) to update the Con Edison 2005 System Reliability Study, which was conducted pursuant to the 2005 Rate Plan on a one-time basis in case the NYISO CRPP, which had just been adopted at that time,[151] could not be completed. The 2005 Rate Plan accordingly provided that 2005 System Reliability Study would be needed to determine if a reliability need exists: "If the NYISO Comprehensive Reliability Planning Process is rejected by the FERC, is abandoned or terminated, or fails to

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[150] Case 06-M-1017, *Order Requiring Development Of Utility-Specific Guidelines For Electric Commodity Supply Portfolios And Instituting A Phase II to Address Longer-Term Issues* (April 19, 2007) ("IRP Proceeding"). All initial and reply comments have been filed in this proceeding, but the Commission has not yet issued a decision.
[151] Federal Energy Regulatory Commission, *New York Independent System Operator, Inc*, 109 FERC ¶ 61,372 (December 28, 2004).

produce annual "Reliability Needs Assessments" for the Company's service territory during the Electric Rate Plan."[152]

The NYISO's CRPP has now been in effect for more than two years and has produced the reliability needs assessment and the comprehensive reliability plan required by its planning process and NYC is a member of the NYISO than can fully participate in that process.[153] There is simply no need for Con Edison to conduct a system reliability study separate and apart from the NYISO CRPP process.

IV. COST OF CAPITAL

A. Capital Structure

1. The Company's Proposal

In its original filing, the Company's Accounting Panel testified that the Company's projected "stand-alone" average capital structure for the rate year should be used to determine the Company's cost of capital: a long-term debt ratio of 48.88%, a common equity ratio of 48.68%, a preferred stock ratio of 1.21%, and a customer deposit ratio of 1.23%. (1354; Exh. 90). In his rebuttal testimony, Company witness Hoglund provided a convincing basis for why the Commission should reference the Company's "stand-alone" capital structure to establish its rates and returns. (2899-2909). As he noted, this approach ensures that the actual sources of the funds invested in the Company are compensated, thereby moderating the Company's capital costs. (2903).

Such an approach also is consistent with that used by the major rating agencies that rate the Company's securities. As noted by Mr. Hoglund, both Moody's and Fitch use stand-alone

[152] 2005 Rate Plan Order, App. 1 at 75.
[153] NYISO, "The Comprehensive Reliability Plan 2007: A Long-Term Reliability Assessment Of New York's Bulk Power System, Final Report (September 18, 2007).

financial ratios (including measures of capital structure strength) in their analyses and rating decisions. (2906).

Finally, use of the Company's stand-alone capitalization conforms with recent Company rate plans. For example, the Joint Proposal adopted by the Commission in the recent Con Edison steam case[154] relies upon the Company's actual capital structure in calculating the rate of return for purposes of the earnings sharing mechanism. The same is true for the Joint Proposal recently adopted for the Company's gas business.[155]

2. The Staff Rate Panel's Capitalization Reallocation Proposal Should Be Rejected

In contrast to this stand-alone capital structure, the Staff Finance Panel referenced the filed financial statements of the Company's corporate parent, Consolidated Edison, Inc. ("CEI"), to re-engineer the Company's capital structure as follows: a long-term debt ratio of 49.65%, a preferred stock ratio of 1.13%, a common equity ratio of 47.98%, and a customer deposit ratio of 1.24%. (3724). As illustrated in Exhibit 250, page 1 of 2, the Staff Finance Panel accomplished this result by transferring both debt and equity from utility operations to non-utility operations so as to "reflect a more appropriate allocation of capital between utility and non-utility operations." (3722).

The financial re-engineering recommended by the Staff Finance Panel constitutes a regulatory "solution" in search of a problem and should be rejected by the Commission. While such financial re-engineering might be appropriate in instances where utilities engage in "double leveraging", *i.e.*, whereby the holding company issues debt and uses those funds to make equity

[154] Case No. 05-S-1376, 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, Order Determining Revenue Requirement and Rate Design (issued September 22, 2006).
[155] 2007 Gas Rate Plan Order, App. I, p.13.

investments in a utility subsidiary, Staff readily acknowledges that the Company has not engaged in such activity. (3716).

The absence of double leveraging, however, did not deter Staff's headlong rush to reallocate the Company's capitalization. Ignoring observable market practice for the financing of independent competitive electric companies, the Staff Finance Panel proposes a debt rating for CEI's competitive businesses equal to that of the Company, thereby producing a theoretical need for 61.5% equity ratios for each of the competitive energy businesses. (2904) The Staff Finance Panel, however, fails to provide evidence of the prevalence of "A" rated competitive generation businesses, because such ratings are very uncommon. As noted by Mr. Hoglund, competitive electric businesses generally have non-investment grade ratings with substantially higher levels of book leverage than those proposed by the Staff Finance Panel. (2905). For example, the largest public generation businesses (*e.g.*, Dynegy, Mirant, NRG Energy and Reliant) have average net debt balances of nearly 60% of total book capitalization.

Since the Staff Finance Panel did not apply a comparative analysis to the capital structure of the competitive parts of CEI, its proposed reallocation adjustment in effect serves to regulate indirectly the capitalization and financing of these other subsidiaries. The Staff Finance Panel, however, failed to establish the basis for its regulation of the capitalization of CEI's competitive businesses, whether directly or through an adjustment to the Company's actual capital investments in support of their customers.

The Staff Finance Panel's proposed reallocation adjustment is particularly inappropriate in light of the Company's circumstances. As testified to by Mr. Hoglund, CEI has no current plans to increase significantly its investments in its unregulated subsidiaries and is currently undertaking a strategic review of its competitive generation investments. (2907). Moreover,

CEI's investment in its unregulated subsidiaries is relatively modest. For example, as set forth in its Form 10-Q for the quarter ended September 30, 2006 (Exh. 194, p. 6), CEI's non-utility plant amounted to less than five percent of its total net plant, which relationship continues to the present. As indicated by Mr. Hoglund during his redirect, given such marked divergence in the sizes of the businesses, there is no compelling need that the Company's unregulated affiliates maintain the Company's "A" rating. (2999).

Such dramatic size divergence also helps explain why, as testified by Mr. Hoglund, the rating agencies have provided no indication that CEI's current investment in its unregulated subsidiaries has had an impact on CEI's rating. (2998-2999). The fact that the rating agencies do not view CEI's non-regulated subsidiaries as a source of significant additional risk further underscores the arbitrariness of Staff's proposed reallocation adjustment. For example, the Standard & Poor's Business Profile rating of "2" is applied to both Con Edison and its parent, CEI. (2906-2907). CEI's unregulated investments, as currently constituted, simply do not justify Staff's proposed reallocation.

The Company also vigorously disagrees with Staff's reallocation proposal since Staff incorrectly assumes that the equity and debt in the non-regulated portion of CEI's business will not change from the levels at June 30, 2007. (2907). As noted by Mr. Hoglund, CEI expects to be able to retire the remainder of its debt and may add equity at the non-regulated subsidiaries before and during the rate year. CEI has already called and retired $325 million of holding company debt in May 2007. An additional $200 million of debt will mature in August 2008. Consistent with Commission policy, capitalization analysis should reflect the best information available about what the rate year capitalization will be rather than what historically it has been. (2908).

Staff's recommended capital structure also is contrary to the position advocated by Staff and adopted by the Commission in the recent National Grid/KeySpan merger proceeding.[156] As noted by Company witness Hoglund, in the order approving that merger, the Commission excluded consideration of both the consolidated United States group capital structure and the global group capital structure in its determination of the utility subsidiaries' capitalization,[157] so long as the utility subsidiaries maintain an investment-grade rating. (2901). The Commission's determination to forgo in the National Grid/KeySpan merger proceeding the very sort of adjustment that Staff wishes to visit upon the Company in this proceeding was not taken lightly, particularly in view of the Commission's microscopic review of the terms of that merger. As further noted by Mr. Hoglund, application of a less favorable capitalization analysis to the Company seriously disadvantages the Company, by undermining the Company's ability to attract capital on competitive terms. (2902). The Staff Finance Panel certainly has not presented a compelling basis for such disparate and discriminatory treatment.[158]

3. Westchester and Consumer Power Advocates Capital Structure Proposals are Not Supported by Credible Evidence

In addition to Staff, both Westchester and Consumer Power Advocates propose capital structures for the Company. Neither proposal, however, provides a basis for rejecting the Company's proposed capital structure.

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[156] Case 06-M-0878, Joint Petition of National Grid PLC and KeySpan Corporation for Approval of Stock Acquisition and Other Regulatory Authorizations, Abbreviated Order Authorizing Acquisition Subject to Conditions and Making Some Revenue Requirement Determinations for KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island (issued August 23, 2007).

[157] The Company would note that this sort of approach would allow the very sort of double leveraging that Staff allegedly finds so problematic.

[158] Staff's position in the Orange and Rockland Temporary Rate Proceeding (Case No. 06-E-1433) provides further evidence of the absence of a standardized Staff capitalization analysis. In that case, Staff supported a 50% equity ratio. (2905-2906).

In their testimony, Westchester witnesses Liberty and Radigan preface their capital structure recommendation with the admission that "neither of us are experts in the cost of capital." (5452) These witnesses quickly verify their acknowledged lack of expertise by recommending that the Company's revenue requirement be set with an assumed equity of ratio of 44%. (5454). The witnesses do not address the Company's future financing plans and needs. They marshal no academic or theoretical justification for their recommendation. They do not even pretend to consider the potentially disastrous effect of their recommendation on the Company's credit rating. Rather, their "analysis" consists of a passing reference to the equity ratio granted by the Commission in another proceeding, and the bald assertion that "the Company's risk level has gone down in recent years." (5454). The sole "justification" for Westchester's recommendation is that it serves to reduce the Company's revenue requirement by $80 million. Such a transparently results-oriented recommendation, however, hardly provides a reasoned basis on which to determine the Company's capital structure. Accordingly, the Commission must reject Westchester's position.

Equally deficient is the recommendation of Consumer Power Advocates witness Dowling who testifies that the equity ratio, as well as the return on equity, be the same as that included in the Joint Proposal approved by the Commission in Case 06-G-1332. (4807-4808). Mr. Dowling offers no analysis in support of his recommendation. The sole basis for this recommendation is the wholly unsubstantiated allegation that it allegedly will save customers "$696 Million over the term of a three year rate plan." Given its complete lack of support, the Commission must reject Mr. Dowling's equity ratio recommendation.

B. Cost of Equity

The cost of equity is the rate of return component that must be offered to investors to make them willing to buy the stock under consideration on fair and reasonable terms. Fair and reasonable terms cannot be directly measured in the marketplace, but must be estimated using various financial measures that take into consideration the legal and regulatory ratemaking environment and investor perception. As noted by Dr. Morin in his direct testimony, no one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. (2587-2588). Academic literature, as detailed by Dr. Morin, provides strong support for using multiple methods.

Accordingly, Dr. Morin developed the market cost of equity for Con Edison by performing studies employing the Capital Asset Pricing Model ("CAPM"), Risk Premium, and Discounted Cash Flow ("DCF") methodologies. Specifically, he performed two CAPM analyses, one using a plain vanilla CAPM and another using an empirical approximation of the CAPM ("ECAPM"). He also performed two market risk premium analyses: (1) a historical market risk premium analysis of the electric utility industry, and (2) an analysis of allowed book risk premiums in the electric utility industry. Finally, he performed market-based DCF analyses on two surrogates for the Company's electricity delivery business: a group of investment-grade electricity delivery utilities and a group consisting of the companies that make up Moody's

Electric Utility Index.[159] Based upon these analyses, Dr. Morin determined a cost of equity for the Company of 11.2%.[160] (2633-2634).

The Staff Finance Panel, on the other hand, relied primarily on a two-stage market-based DCF analysis of a group of 29 electric utilities. The Staff Finance Panel also applied market-based CAPM and ECAPM analyses to the same group of companies to produce a recommended cost of equity of 9.04%. The Staff Finance Panel then applied several adjustments to this result. Specifically, they subtracted 29 basis points based on their proposed credit quality adjustment, added 20 basis points to cover equity issuance expenses expected during the rate year, and subtracted ten basis points to account for the alleged risk reduction provided by Staff's proposed approach to revenue decoupling. The result, 8.95%, was rounded to 8.9% to produce the Staff Finance Panel's recommended return on equity for the Company. (3754).[161]

As discussed below, the Staff Finance Panel's analyses are plagued by errors that produce an invalid cost of equity recommendation. Perhaps most telling, however, is the fact that their recommendation is more than 200 basis points (or two full percentage points) below the authorized returns of their own hand picked group of comparable companies. (2666K-2666L). Simply stated, the Staff Finance Panel's recommendation is an outlier. The Staff Finance Panel's understated cost of equity recommendation does not provide a fair and reasonable return on the book value of the equity investment in the Company, and may further

[159] As acknowledged by the Staff Finance Panel, it has been the Commission's practice over the past few decades to use proxy groups to calculate a utility's Return on Equity ("ROE"). The primary reason for using such proxy groups is to "smooth out any irregularities in any data that might develop for one particular company." (3792-3824; 3793-3799). Moreover, certain of the variables utilized in the DCF and CAPM methodologies (*e.g.*, beta, stock market price) are market based and therefore not readily available for utilities such as the Company whose stock is not publicly traded. This lack of market information would make it difficult to utilize the DCF and CAPM methodologies to calculate the Company's ROE on a stand alone basis.

[160] In the event that the Commission approved a three-year rate plan for the Company, a 30-basis stay-out premium would be added to produce a cost of equity for the Company of 11.5%. (2693).

[161] As noted by Dr. Morin, CPB witness Niazi's testimony is nearly identical to that of the Staff Rate Panel. (2666QQ). Therefore, the Company's criticisms of the Staff Finance Panel would apply equally to Mr. Niazi. In the interest of economy, the Company will not repeat them herein.

subject the Company to a ratings downgrade. Any such downgrade will have the immediate and deleterious impact of increasing the cost and difficulty of financing the extensive system improvements that Staff itself supports.

For these reasons, the Commission should reject the Staff Finance Panel's cost of equity recommendation. The cost of equity recommendations offered by the NYPA Panel and Westchester witnesses Liberty and Radigan are equally without basis and also should be rejected by the Commission.

1. Standard of Review

New York has empowered the Commission with the authority to determine whether rates are just and reasonable (N.Y. Pub. Serv. Law §65(1)) and sufficient for the provision of safe and adequate service. As noted by Dr. Morin in his testimony, the heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. (2583). The United States Supreme Court has defined the legal principles that provide the foundation for the notion of a fair and reasonable return.

"The [rate of] return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm., 262 U.S. 679, 693 (1923). Such rates must permit the public utility to earn a return on the value of the property that it employs for the convenience of the public equal to that generally being made "on investments in other business undertakings which are attended by corresponding risks and uncertainties." *id.* at 692-93. The Supreme Court reaffirmed this holding in Fed. Power Comm. V. Hope Natural Gas, 320 U.S. 591 (1944), stating that the ROE, a component of

the overall rate of return, should be "sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital." 320 U.S. at 603. Accordingly, the Hope and Bluefield standards should guide the current discussions.

2. Con Edison's Proper Return on Equity

As noted above, the Company's expert witness, Dr. Morin, employed a market-based CAPM analysis, a market-based ECAPM analysis, as well as two risk premium analyses using historical market and allowed book risk premium data from electric utility industry aggregate data. He also performed market-based DCF analyses on two surrogates for the Company: a group of investment-grade electric distribution utilities and a group representative of the electric utility industry, namely, Moody's Electric Utility Index. The results from all the various tests are summarized in the table below.

METHODOLOGY	ROE
CAPM	12.0%
Empirical CAPM	12.2%
Historical Risk Premium Elec Utility Industry	10.7%
Allowed Risk Premium	10.7%
DCF S&P Elec Distribution Utilities Value Line Growth	11.2%
DCF S&P Elec Distribution Utilities Zacks Growth	11.4%
DCF Moody's Elec Utilities Value Line Growth	10.6%
DCF Moody's Elec Utilities Zacks Growth	10.4%

The average result from the three principal methodologies is as follows:

CAPM	12.1%
Risk Premium	10.7%
DCF	10.9%
AVERAGE	11.2%

The overall average result is 11.2% for the average electricity distribution utility. Dr. Morin has weighted all three methods equally. (2633).

This rate of return is sound and reasonable not only because Dr. Morin relied on a range of costing methodologies, but also because his conclusions were supported by numerous financial indices. His DCF estimate of 10.9% was based on earnings growth estimates from several sources, including Value Line, Zacks Investment Research Inc. ("Zacks"), Moody's and Standard & Poor's. The CAPM estimate of 12.1% was supported by seventy-five years of actual equity and debt return data from Ibbotson Associates. The risk premium estimate of 10.7% was based on a historical risk premium for the electric utility industry as a whole, using *Moody's Electric Utility Index* as an industry proxy, and an allowed risk premium. The allowed risk premium compared the historical risk premiums implied in the ROEs allowed by regulatory commissions for electric utilities over the last decade relative to the contemporaneous level of the long-term Treasury bond yield. By relying on these various costing perspectives, the Company's ROE estimate of 11.2% is a far more accurate measure of the market return required by a common equity investor than that recommended by the Staff Finance Panel.

Each of the three methodologies employed by Dr. Morin is discussed below. This discussion also will highlight the deficiencies of Staff's ROE recommendation.

a) <u>DCF Method.</u>

The DCF method is based upon the idea that the price that is paid for a company's stock in the market represents the sum of the present value of all future expected cash flows. Specifically, an equity investor's expected market return can be viewed as the sum of an expected dividend yield, plus the sum of an expected growth rate of future dividends and stock price. As noted above, Dr. Morin applied the DCF model to two proxies for the Company's

electric delivery operations: a group consisting of investment-grade dividend-paying electric distribution utilities and a group consisting of those electric utilities that make up Moody's Electric Utility Index. In calculating the dividend yield, Dr. Morin used the current market dividend yields as reported in the latest edition of Value Line's VLIA software. These yields used the current market price of the securities.

In determining growth, Dr. Morin used analysts' long-term growth forecasts as tabulated by Zacks, as well as Value Line's growth forecast. Dr. Morin separately applied the DCF methodology, using the Zacks and Value Line long-term growth forecasts, to each of his two proxy groups, thereby producing four separate DCF results. He correctly rejected historical growth rates as proxies for future growth since they already are incorporated in analysts' growth forecasts. In applying the DCF model, Dr. Morin also did not consider dividend growth, since it is widely expected that utilities will continue to lower their dividend payout ratio over the next several years. Finally, Dr. Morin added a flotation cost allowance calculated as a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

Dr. Morin's four separate DCF results ranged from 10.4% to 11.4%, for an average result of 10.9%.

As discussed in the rebuttal testimony of Dr. Morin, the Staff Finance Panel misapplies the DCF methodology and then relies on this misapplied methodology to the near-exclusion of any other approach. The Staff Finance Panel has chosen to rely heavily on the DCF method by giving two-thirds weight to the DCF results. In light of the myriad deficiencies inherent in Staff's application of the DCF methodology, the Commission must reduce the two-thirds weight allocation proposed by the Staff Finance Panel. The Company would note that in his recent

recommended decision in the current National Fuel Gas rate case, Judge Bouteiller, recognizing that the DCF methodology provides less reliable results when market prices and book investments do not match (such as has been the case for past few years), recommended that *at most* the DCF should receive equal weight with the CAPM.[162]

First, the market price for stocks used as input in the dividend yield component may be unduly influenced by structural changes (*e.g.*, the introduction of competition) and changing investor expectations in the utility industry. (2666H).

Second, the traditional DCF model is based on a number of assumptions, some of which appear unrealistic in today's capital market environment. (2666H-2666I). For example, the standard infinite growth DCF model assumes a constant market valuation multiple, that is, a constant price/earnings (P/E) ratio. This assumption is unrealistic given the surges in P/E ratios experienced by utility stocks in the last decade. Contrary to the standard DCF assumption of a constant P/E ratio, stock prices may not necessarily be expected to grow at the same rate as earnings and dividends by investors.

The Staff Finance Panel's own DCF results, set forth in Exhibit 255 (page 2 of 3), highlight their unreliability. (2666J). The DCF results shown in the last column are widely dispersed, ranging from a low of 6.4% to a high of 15.4%. Several estimates are barely above, and even below, the cost of debt for these companies. The huge variability in the results demonstrates the lack of reliability of the DCF approach and the need to employ, and rely more heavily upon, a variety of methodologies when estimating the cost of capital.

[162] Case 07-G-0141, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service, Recommended Decision (issued September 28, 2007) (see pp. 9-10).

The annual DCF model used by the Staff Finance Panel incorrectly ignores the time value of quarterly dividend payments and assumes that dividends are paid once a year, at the end of the year. (2666O). Since investors are aware of the quarterly timing of dividend payments, this knowledge is reflected in stock prices. As noted by Dr. Morin, the use of the annual version of the DCF model understates the cost of equity by approximately 20 basis points.

In their implementation of the DCF model, shown on Exhibit 255, the Staff Finance Panel uses the average dividend yield over the six months prior to July 2007. (2666P). As discussed by Dr. Morin, this results in the improper use of stale stock market prices to calculate dividend yield. Rather, the stock price to employ is the current market price of the security at the time of estimating the cost of equity, rather than some historical average stock price reaching back six months.

The Staff Finance Panel also relies exclusively on the earnings retention growth method in the crucial second stage of their DCF analysis. In his rebuttal testimony, Dr. Morin identifies four separate defects associated with the earnings retention growth technique: (1) the method is logically circular, for it required the Staff Finance Panel to assume the ROE answer to begin with; (2) its inconsistency with the academic empirical evidence; (3) the potential lack of representativeness of Value Line's forecasts as proxies for the market consensus; and (4) a technical error. (2666Q-2666V).

The Staff Finance Panel relies exclusively on Value Line forecasts for its major inputs into the DCF analysis, including short-term dividend forecasts, expected return, new stock issues, and expected retention ratio. Staff's sole reliance on Value Line growth forecasts runs the real risk that such forecasts are not representative of investors' consensus forecast. Rather, as advocated by Dr. Morin, one should utilize a myriad of analysts' growth forecasts, since together

they will provide reliable estimates of the investors' consensus expectations likely to be impounded in stock prices. (2666V).

As noted by Dr. Morin, investors are expecting growth rates higher than Staff used in its DCF calculations. For its group of 29 electric utilities, Staff has found (*see*, Exh. 255, page 2, columns N and W) average growth rates of 4.3% and 5.0% for the first and second stage of the DCF analysis, respectively. The average long-term growth forecast for the Staff Finance Panel's proxy group, as reported by Value Line and Zacks Investment Research, however, are 6.1% and 6.9%, respectively (midpoint 6.5%). (2666X). This is almost 180 basis points (1.8%) above Staff's long-term growth estimate of 4.3% - 5.0% (midpoint 4.7%).

In addition to the various flaws in the Staff Finance Panel's application of the DCF methodology highlighted by Dr. Morin, Company witness Hoglund identified a more basic flaw in their analysis. Specifically, their DCF analysis is inherently problematic since it fails to relate the market-derived rates to the book measures upon which the Commission sets returns. Instead of applying the DCF methodology in such an asymmetrical manner, a more structurally parallel approach should be employed. As noted by Company witness Hoglund, "If you are going to set returns based on market derived analysis then you need to set them with respect to market value. …if you are going to set book derived returns, they need to be on a book basis." (2987). As a simple example of coherent analysis, Staff's analysis would be internally consistent, and therefore might produce a fair and reasonable return, if book values per share were substituted for market prices in its DCF analysis.

Dr. Morin agrees with Mr. Hoglund's identification of the problems associated with applying market derived estimates of returns to book values, as set forth his argument in his initial testimony (2590-2598) and rebuttal. (2666M-2666N). Moreover, as noted by Dr. Morin,

other regulatory commissions share these reservations with the reliability of the DCF model. As a result, they refuse to rely solely on the results of the DCF model in setting a utility's allowed ROE. Indeed, there is a particular sensitivity regarding the need to avoid exclusive reliance on the DCF model when, as today and for the last several years, market/book ratios exceed unity. (2594-2595).

If market values are greater than book equity investment, Staff's approach of applying market-derived values directly to the book measures upon which the Commission sets returns will understate a utility's required return thus failing to satisfy the just and reasonable standard for setting such returns. That market values today exceed book values in the United States economy is evidenced by Merrill Lynch's report that the S&P 500 index has an aggregate market value that is 2.9 times its historic book equity investment (including goodwill and other intangible assets) (see Exh. 259, p. 44; 2911-2912). The impact of this inherently flawed application of market-derived returns (which are *marginal* returns) to the task required of the Commission (*i.e.*, to set returns on historic book investment, which are aggregate vintage returns) explains why CEI is ranked 481st in terms of ROE in the S&P 500. (2913).[163]

[163] The Company also would note that the topic of above-book market values has been addressed by former Commission Chairman Alfred Kahn, who noted that these values provide information that should not be ignored by the Commission. Dr. Kahn stated that above book security prices may be attributable to a belief by investors they were getting a return commensurate with their investment because future security prices would be increasing and if so, contemporaneous earnings/price ratios must have understated the true cost of equity capital. Such investors thought they would be getting a better return than would be indicated by the earnings/price ratio. Any effort by utility commissions to hold earnings on the companies' rate bases thereafter to the low rates suggested by those ratios, as Staff is proposing in this proceeding, will "destroy" this otherwise legitimate expectation and result in deflation of security prices. Such action, by thus increasing earnings/price ratios, will have demonstrated that the true cost of capital was higher than they had originally inferred. By ignoring market prices above book value or inferring that they unequivocally mean a reduced cost of capital, the Commission will be taking advantage (at least in the short term) of investors' "favorable anticipations." A. Kahn, The Economics of Regulation: Principles and Institutions, Volume I (1971) (pp. 48-49; n. 69)

b) CAPM

The second methodology used by Dr. Morin was the CAPM. As noted above, Dr. Morin performed two CAPM analyses, one using a plain vanilla CAPM and another using an ECAPM. Under this model, the cost of equity is determined as the sum of the current market return on a risk-free investment plus the stock's beta coefficient multiplied by the market risk premium ("MRP"). CAPM takes into consideration developments in financial theory in which the total risk (or uncertainty of returns) of an asset is divided into two parts: unsystematic risk (or uncertainty) and systematic risk (or uncertainty). Unsystematic risk represents fluctuations in returns due to events specific to the company in question. Systematic risk, on the other hand, represents fluctuations due to the effect on the firm of economy-wide forces. The exposure created by unsystematic risks can be eliminated by holding a diversified portfolio, while systematic risk cannot be alleviated by a diversified portfolio.

Under CAPM theory, investors need only be concerned with systematic risk. This systematic risk (uncertainty of returns for) of an asset is measured by beta. The level of beta of an asset represents the risk contribution of that asset to the overall risk of a diversified portfolio. Dr. Morin used Value Line's average beta for a sample of widely-traded investment-grade electric distribution utilities of 0.91. He checked this result against the average beta of the companies that comprise Moody's Electric Utility Index, as a second proxy for the Company and found that beta to be 0.94. (2605).

In determining the risk-free rate of return, Dr. Morin used 4.8% based on the current market prices and coupons for 30-year Treasury bonds. (2604).

An additional parameter required to calculate the required market cost of equity under the CAPM method – the expected difference between the market-required return on common stocks

and the yield on long-term government bonds, *i.e.*, the MRP – is not observable directly in the marketplace. For the MRP, Dr. Morin used 7.6% based on the results of both forward-looking and historical studies of long-term market risk premiums. (2605-2606).

Ibbotson Associates' *Stocks, Bonds, Bills and Inflation, 2006 Yearbook*, reports that from 1926-2005, the historical MRP of common stocks over the income component of long-term Treasury bonds is 7.1%. The forward looking study involved a DCF calculation of the cost of equity for the market as a whole and subtracting from that number the estimate of the "risk-free" rate to determine the expected market risk premium. Specifically, a DCF analysis applied to the aggregate equity market using Value Line's aggregate stock market index and growth forecasts indicates a prospective MRP of 8.1%. Dr. Morin then averaged the historical (7.1%) and prospective MRP estimates (8.1%) to produce a MRP of 7.6%.

Inserting those input values in the CAPM equation, namely a risk-free rate of 4.8%, a beta of 0.91, and a MRP of 7.6%, according to Dr. Morin, the CAPM estimate of the cost of common equity for the Company is: 4.8% + 0.91 x 7.6% = 11.7%. This estimate becomes 12.0% with flotation costs. (2608).

Since empirical research indicates that a CAPM-based estimate of the cost of capital underestimates the market return required from low-beta securities, such as those of CEI, Dr. Morin also calculated the Company's market cost of capital using the ECAPM. The result of the ECAPM, 12.2%, was averaged with the CAPM result, 12.0%, to produce an average CAPM of 12.1%. (2612).

While Dr. Morin and the Staff Finance Panel agreed on the inputs for the risk free rate and beta estimates components of the CAPM, they disagreed on the MRP. (2666Z-2666AA). As noted by Dr. Morin, the Staff Finance Panel mistakenly relied exclusively on Merrill Lynch's

in-house forecast, rather than the results of the market over an extended period (which allows for the averaging out of short-term aberrations) for the overall equity market to calculate the MRP. The Staff Finance Panel's MRP estimate is inconsistent with regulatory decisions and serves to improperly understate their CAPM results by approximately 100 basis points. (2666DD).

In addition to the deficiencies identified by Dr. Morin, as observed by Company witness Hoglund, Staff's application of the CAPM suffers from the same defect as its application of the DCF methodology described above. That is, while the inputs to CAPM are derived entirely from the market, they are applied to book value investments to calculate a utility's recommended ROE. (2913-2914). Calculation of a market return and its application to a book value of equity is not justified and dramatically understates the fair rate of return that the Staff Finance Panel itself acknowledges is the Commission's responsibility to provide. To rectify the error in applying a market-derived CAPM to the Company's accumulated book value of equity, Staff could have multiplied its derived return by a factor that related the current market value of United States equities to their underlying tangible accumulated book values of equity. For the S&P 500, which constitutes approximately 75% of the U.S. equity markets, that factor was 6.4 as shown on Exhibit 191.

c) <u>Risk Premium</u>

In addition to his DCF and CAPM studies, Dr. Morin also employed two risk premium methodologies to ascertain the required cost of equity for the Company. First, Dr. Morin estimated the historical risk premium for the electric utility industry with an annual time series analysis applied to the industry as a whole, using *Moody's Electric Utility Index* as an industry proxy. The risk premium was estimated by computing the actual realized market return on equity capital for Moody's Index for each year, using the actual stock prices and dividends of the

index, and then subtracting the long-term government bond return for that year. As noted by Dr. Morin, the average risk premium over the period was 5.6% over long-term Treasury bond yields, and the risk free rate is 4.8%. Therefore, the implied cost of equity for the average electric utility from this particular method is 4.8% + 5.6% = 10.4% without flotation costs and 10.7% with flotation costs. (2612-2613).

Dr. Morin also performed an analysis of allowed risk premiums in the electric utility industry. Specifically, he examined the historical risk premiums implied in the ROEs allowed by regulatory commissions for electric utilities over the last decade relative to the contemporaneous market yields for long-term Treasury bonds. Dr. Morin concluded that a risk premium of 5.9% should be allowed for the average risk electric utility. Combining this risk premium estimate with the current long-term Treasury bond yield of 4.8% implies a cost of equity of 10.7% for the average risk utility. (2617).

The average risk premium result is 10.7%, as both the historical risk premium and allowed risk premium estimates are identical. (2620).

In his rebuttal testimony, Dr. Morin refuted the Staff Finance Panel's criticisms of his risk premium analysis. The Risk Premium approach is conceptually sound and firmly rooted in the conceptual framework of Capital Market Theory. It is widely used by analysts, investors, and expert witnesses. Moreover, one advantage of Risk Premium over DCF is that the former takes a broader time-series perspective rather than a snapshot point-in-time viewpoint, and is therefore less vulnerable to the vagaries of any one particular capital market environment. (2666HH-2666JJ).

Regarding the Staff Finance Panel's criticism that Dr. Morin has not demonstrated whether the Company is more or less risky than the companies that make up Moody's Electric

Utility Index, Dr. Morin correctly notes that over most of the period that covers his historical risk premium study, *i.e.*, 1926-2005, electric utility companies were relatively homogenous in risk and under the umbrella protection of regulation for all of its functions (*i.e.*, power generation, transmission, distribution). (2666HH).

The Staff Finance Panel also criticized Dr. Morin's risk premium methodology on the grounds that it assumes that the risk premium is constant over time. In response, Dr. Morin noted that to the extent that the historical equity risk premium estimated follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. He found no evidence that the market price of risk or the amount of risk in common stocks has changed over time, that is, no significant serial correlation in the successive market risk premiums from year to year. Therefore it is reasonable to assume that these quantities will remain stable in the future. (2666HH-2666II).

Finally, the Staff Finance Panel's criticism of allowed risk premiums by regulators is equally unconvincing. Staff argues that the determination of an allowed return is flawed because it does not factor in particular features associated with past ROE decisions, such as multi-year rate plans and stayout premiums. As Dr. Morin noted, however, several ROE awards are part of incentive mechanisms with substantial upside potential, so that the allowed risk premium is more often than not understated. As such, his allowed risk premium estimate is very likely a conservative one. (2666JJ).

3. <u>Flotation Costs</u>

Dr. Morin testified that the Company's return on equity should be adjusted to include an allowance for flotation costs. (2629-2633). Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts

that must be provided to place the new securities. Flotation costs for common stock are analogous to the flotation costs associated with past bond issues which, as a matter of routine regulatory policy, continue to be amortized over the life of the bond, even though no new bond issues are contemplated. In the case of common stock, which has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation costs requires an upward adjustment to the allowed return on equity.

While both Dr. Morin and the Staff Finance Panel agree on the need for a flotation cost adjustment, they disagree on its magnitude. The Staff Finance Panel recommends an allowance of 20 basis points (3749), while Dr. Morin recommends an allowance of 30 basis points. (2631). The Staff Finance Panel's recommendation is inadequate, however, since they fail to account for all the unrecovered flotation costs associated with all past equity issues. Accordingly, the Staff Finance Panel's DCF estimates of equity costs are downward-biased by approximately 10 basis points.

4. <u>Staff's Proposed Return Adjustments Are Improper</u>

a) <u>Credit Quality Adjustment</u>

The Staff Finance Panel proposes that the Company's ROE be reduced by 29 basis points (0.29%) to account for credit quality differences between the Company and the proxy group. (3745-3748). Staff argues that the Company is less risky than the comparable group because its bond ratings are slightly higher than those of the comparable companies. Specifically, the Staff Finance Panel's adjustment is based on the yield differentials between utility bonds rated A and BBB over the past six months. As discussed below, the Staff Finance Panel's credit quality adjustment suffers from a number of fatal defects.

First, as noted by Company witness Hoglund, the Staff Finance Panel has provided no evidence of any relationship between credit quality and required or observed equity returns in the utility industry. (2917). Rather, they simply and improperly presume that differentials in bond yields will translate neatly into common stock return differentials. As set forth in Exhibit 188, however, there is no correlation between the Staff Finance Panel's DCF results for the companies in their proxy group and the bond ratings of these companies. (2917). Accordingly, the Staff Finance Panel's credit quality adjustment not only lacks a theoretical basis, it also is not supported by the Staff Finance Panel's own data.

Second, even if credit ratings had been in any way correlated with equity returns, the Staff Finance Panel fails to account adequately for the Company's deteriorating credit rating. As noted by Dr. Morin, the Company's credit ratings are already fragile as indicated by the "negative outlook" status of its bonds due in part to weak financial ratios. (2666EE). The Staff Finance Panel's severely understated recommended ROE, combined with the imposition of increased penalties and the implementation of an RDM, only serve to worsen an already bad situation. The distinct possibility of a downgrade of the Company's credit ratings certainly undermines the validity of any sort of credit quality adjustment.

As testified to by the Company's Infrastructure Investment Panel, Con Edison will be continuing and increasing its already substantial capital expenditure program over the next few years. By and large, Staff in this proceeding has been supportive of such program. The Company's ability to tap capital markets and attract funds on reasonable terms is absolutely critical to the implementation of Con Edison's capital expenditure program in an efficient, cost effective manner. As noted by Dr. Morin, this is certainly no time to apply a return decrement

and reduce the Company's return, particularly in light of the increasingly volatile and unpredictable capital markets. (2666EE).

Finally, as noted by Dr. Morin, Staff's proposed reduction of 29 basis points as applied to the Company's bonds, yields an implausible scenario. (2666EE-2666FF). According to the Staff Finance Panel, the yield on the Company's long-term bonds is approximately 6.0% as of the time the testimony was filed. (3746). Applying the Staff Finance Panel's downward adjustment of 29 basis points to the yield on the Company's bonds would produce a yield of 5.7%. According to the Staff Finance Panel, that would be less than the yield on utility bonds rated AA. (*i.e.*, 5.84%). (2746). Such a situation, however, would be highly improbable given that Con Edison's bonds are rated single A and are already on negative outlook, with a possibility of a downgrade to the BBB level. This scenario therefore is unlikely and quite outside the bounds of reasonableness, particularly in light of Staff's recommended ROE of only 8.9%.

For all these reasons, the Staff Finance Panel's downward ROE adjustment of 29 basis points should be rejected by the Commission.

b) <u>RDM Adjustment</u>

The Staff Finance Panel also has proposed a downward ROE adjustment of ten basis points to account for what it considers to be the risk-reducing effect of implementing an RDM. (3749-3754). As discussed in the testimony of Company witnesses Hoglund and Morin, this proposed adjustment is improper, unsupported by evidence, and highly arbitrary.

The Staff Finance Panel's proposed RDM adjustment is anchored by conjecture and unverified supposition, rather than by record evidence. There has been no recent experience with RDMs in New York. As noted by Dr. Morin, experience in other states with the application

of RDMs to electric utilities is extremely limited. By his count, only three investor-owned electric utilities currently are operating under an RDM. (2686). Any predictions of reduced risk are plainly premature, especially when the specific features of the RDM to be applicable to the Company remain undetermined. Instead of reducing risk, an RDM will serve to increase regulatory risks, particularly the downside risk of the Commission denying timely recovery if deferred balances become too large.[164] In light of these facts, any assumption that an RDM will reduce a utility's downside risk is simply unwarranted. (2919-2920).

In proposing the RDM adjustment, the Staff Finance Panel also fundamentally misconstrues investor perceptions. As noted by Company witness Hoglund, risk—or more correctly, volatility—is not necessarily viewed negatively by equity investors. (2918-2929). To the extent that volatility produces a higher expected value, equity investors will prefer it relative to a less volatile investment with a lower expected return. In actuality, an RDM will act to lower volatility that the investors already accept and replace it with the certainty of lower returns. For example, by confiscating earnings due to weather, Staff's proposed RDM serves to deprive equity investors of the primary source of any upside potential. In an environment where Staff is recommending ROE less than 9.0%, and has advocated new and increased penalties, this hardly constitutes a winning strategy for encouraging equity investment.

In addition, the assumption that a significant risk reduction will occur with the imposition of an RDM is faulty. As stated by Mr. Hoglund, cold weather and variability in usage are risks (volatilities) that are very seldom even mentioned in any analyst's (whether equity or fixed-income) review of key downside risks for Con Edison. They are extremely unlikely to lead to

[164] This increase in regulatory risk warrants a corresponding increase in the Company's ROE, rather than any downward adjustment.

any long-term negative impact on earnings or stock price and extremely unlikely to affect the dividend. (2919).

The Staff Finance Panel speculates that the implementation of an RDM for an electric utility could lead to a credit rating upgrade. (3751-3752). This anodyne forecast is wholly unsupported by any evidence, since to date such a credit rating upgrade has failed to materialize. Indeed, given the Company's circumstances, it is questionable even from a theoretical perspective that Con Edison would qualify for an RDM-related credit rating upgrade. As noted by Company witness Hoglund during cross-examination, rating agencies will be inclined to view the implementation of an RDM for an electric utility positively ***if*** accompanied by actual declines in usage (2974). Actual usage declines are critical, since Staff's proposed RDM, if adopted, will deny a utility the weather related revenues traditionally utilized to offset the costs of meeting increased usage. By all accounts, however, an actual decline in electric usage in the Company's service territory will not be occurring any time soon.

For all these reasons, the Commission must reject the Staff Finance Panel's proposed RDM adjustment.

5. <u>Incompatibility with Allowed Returns</u>

The complete incompatibility of the Staff Finance Panel's rate of return recommendation with actual earned returns on book value for the broader economy and even the regulator-suppressed allowed returns in the utility industry underscores its inherent unreasonableness. While certainly not a precise indication of a company's market cost of equity capital, allowed returns are nevertheless important determinants of investor growth perceptions and investor expected market returns. As noted by Dr. Morin, the currently authorized ROEs for the 29 electric utilities in the Staff Finance Panel's comparable group of electric utilities average is

11.1%. (2666K). Plainly, the Staff Finance Panel's ROE recommendation lies well outside the zone of recently authorized ROEs for electric utilities and indeed for its own sample of companies, and would constitute the lowest ROE allowance in the country for an electric or natural gas utility.

As noted by Dr. Morin, the unreasonable treatment of the Company is thoroughly inconsistent with the economic well being of New York State. (2666M).

6. Staff's Direct Case Increases Regulatory Risk

Staff's recommended ROE of 8.9% should be rejected since it fails to account for the significantly increased risk inherent in Staff's direct case. Much of this risk is associated with the Commission's expressed intention to impose an RDM on the Company. An RDM would increase the Company's regulatory risk because it affords the Commission an opportunity to deny timely cost recovery if deferred balances become too large. (2919). The fact that the Commission has allowed timely recovery of various costs in the past may be scant comfort to investors who are increasingly less willing to extrapolate from past practice, particularly in light of certain of the rate plan components advocated by Staff in this proceeding (*e.g.*, 8.9% ROE, significantly increased penalties).

In addition, the periodic filings required by an RDM subjects the utility to enhanced regulatory scrutiny and serves to undercut the opportunities to be rewarded for efficiencies achieved between rate filings. As the Commission itself has acknowledged, "regulatory lag is the most traditional of ratemaking incentives."[165] Required periodic RDM filings, however, serve to dilute this incentive and thereby impair investor protections. Every occasion that the

[165] Case No. 93-G-0941, Re Brooklyn Union Gas Company, Order Approving Settlement with Modifications (issued October 18, 1994) (see, p. 13).

Company is required to appear before or make a filing with the Commission provides the Commission an opportunity to impose additional regulatory burdens on the Company.

In addition to the enhanced regulatory risk associated with any RDM, the specific form of RDM advocated by Staff presents additional difficulties to the Company. The Staff RDM Panel rejected the incentive proposed by the Company for adding customers. (3963). The Staff RDM Panel also rejected the Company's proposal that it be allowed to retain increased revenues associated with growth in the number of customers. (3972).

Specifically, the Staff RDM Panel opposes the Company's revenue per-customer RDM model and instead recommends that total delivery revenues be trued-up on a class specific basis. In doing so, as explained by the Company's RDM Panel, Staff deprives the Company of an incentive to encourage economic customer growth. (2278-2279). Finally, the Staff RDM Panel rejected the Company's request that it be at risk for weather. (3965-3966). In doing so, Staff has removed any earnings potential relating to hot weather related sales. In summary, the RDM proposed by the Staff RDM Panel acts to remove any upside economic potential for the Company.

Staff's direct case also is designed to provide less than its notional 8.9% ROE. In addition to zealously opposing positive incentives, Staff would subject the Company to significantly increased penalties. (2921). The Company's financial exposure under the existing service reliability and customer service penalties would increase from $95 million to $102 million. Moreover, Staff has proposed two new metrics, Restoration and Remote Monitoring System Reporting, each with multi-million dollar per incident risks and (unlike the existing service reliability and customer service mechanisms) unlimited overall exposure. Specifically, under the Restoration metric, the Company would be subject to a $5 million penalty per event,

with no overall cap on liability. Under the Remote Monitoring System mechanism, the Company would be penalized $10 million for each network not at a 95% reporting rate, and again with no overall liability cap. With 59 networks, this mechanism could subject the Company to enormous penalties.

In addition, Staff has coupled these onerous penalties with other revenue decreasing adjustments. Staff has proposed a one-way true-up of interference costs, which would penalize the Company by not allowing it to recapture higher costs incurred for circumstances beyond its control. Staff also has proposed to discontinue various other reconciliation mechanisms in the context of a one-year rate plan, which have been part of previous multi-year rate plans, without consideration of the increased risks presented by the absence of these mechanisms during a single rate year. Finally, Staff proposes reductions in O&M programs designed to meet Commission standards and to comply with Federal, state, and local requirements. (2921-2922).

The net result of Staff's proposals is to increase significantly the Company's risk while simultaneously and tenaciously eliminating any source of upside earnings potential. The fact that Staff's ROE proposal, which if adopted would be the lowest in the United States in decades, fails to account for these developments provides further evidence of its inherent unreasonableness. This is no mere academic matter. As noted by Company witness Hoglund, by reducing its return to bond-like levels, the Company will be unable to earn a competitive return. An investment in the Company's equity will be transformed into the equivalent of a bond-with-downside. (2922-2923). Such a development, as discussed below, will imperil both the Company's A credit rating and its ability to finance on reasonable terms the massive capital expenditures necessary to enable the Company to continue to provide the level of service that its customers expect and the Commission requires.

7. Staff's Recommended ROE Jeopardizes the Company's "A" Credit Rating

In developing its recommended ROE, the Staff Finance Panel relied primarily on the Generic Finance methodology set forth in a recommended decision issued on July 19, 1994 in Case 91-M-0509.[166] The Generic Finance RD (at 88) reaffirmed the Commission's conclusion from the 1982 generic finance proceeding that an "A" bond rating was a cost effective financial goal. Standard & Poor's currently has assigned an A bond rating to the Company. (3724). During cross-examination, the Staff Finance Panel testified that Staff's presentation in this proceeding is sufficient to support an A bond rating for the Company. (3799). The record in this proceeding does not support Staff's assertion.

Staff recommends that the Company be awarded an ROE of 8.9%. As Dr. Morin observed, if granted, this ROE not only would be the lowest ROE figure for any gas or electric utility in the state, it would be the lowest in the country. (2666C). In his direct testimony, Company witness Hoglund noted that two of the three major rating agencies (*i.e.*, Standard & Poor's and Fitch) have issued a "Negative Outlook" for the Company. (2885). To maintain its current rating, these agencies have stated that the Company must demonstrate cash flow improvement and maintain a strong capital structure with a solid equity ratio.

On cross-examination, Mr. Hoglund reiterated that the major focus of the rating agencies is on cash flow. Weak cash flow, like that experienced by the Company over the past three years, tends to produce lower ratings. (2990). The rating agencies' focus on cash flow is of particular concern to the Company since over the past three years it has been funding a large portion of its capital expenditure program without corresponding cash relief from its customers. (2997). One of the major factors in determining the Company's cash flow is the ROE granted by

[166] Case No. 91-M-0509, Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York State Utilities, Recommended Decision (issued July 19, 1994) ("Generic Finance RD").

the Commission. In this ratings environment, Mr. Hoglund concluded that if the Commission adopts the Staff Finance Panel's proposed 8.9% ROE, the Company likely will be unable to maintain its A credit rating. (2991). The prospects of maintaining an A rating appear even more unlikely given, as discussed above, the enhanced regulatory risk inherent in Staff's case.

The downgrade of the Company's credit rating will have an immediate negative impact. During the proposed three-year rate period, the Company will require an extraordinary amount of capital – over $5 billion - from investors. (2881). As noted by Company witness Hoglund, if the Company was downgraded from an A rating to a BBB rating, the Company would incur additional debt financing costs. Given the size of the Company's capital expenditure program, this amounts to significant additional costs.

Given the possible negative financial repercussions, the Commission must reconsider the very regulatory policies described above that imperil the Company's A rating. As alluded to by Mr. Hoglund during his cross-examination, it took the Company many years to recover from the negative fallout associated with suspending its dividend. (2986).

8. <u>NYPA's and Westchester's Cost of Equity Recommendations</u>

Westchester witnesses Liberty and Radigan recommend that a return allowance of 9.7% be applied to the Company's common equity capital for ratemaking purposes. They base their recommendation on returns allowed in several recent Commission cases, particularly the 9.7% in the Company's last gas base rate case (Case 06-G-1332).[167] (5453). As noted by Dr. Morin, this approach stands in sharp contrast with the estimation practices of expert witnesses on cost of capital who have provided detailed, factually supported, professional testimony setting forth the

[167] Consumer Power Advocates witness Dowling also seems to be advocating that the Commission adopt an ROE of 9.7%. (4807-4808). His "analysis" suffers from the same faults as that of Messrs. Liberty and Radigan and therefore also should be rejected by the Commission.

results of rigorous analysis. (2666RR). The Commission, investment analysts, finance experts, corporate analysts, and finance professionals consistently rely on a variety of such scholarly financial analyses and models, employing a variety of financial methods to arrive at their cost of capital recommendations.

Westchester witnesses, however, offer no evidence that they independently developed any samples of comparable risk companies, or performed a DCF analysis, CAPM analysis, risk premium analysis, or comparable earnings analysis, to arrive at their recommendation. In fact, Messrs. Liberty and Radigan candidly admit to no professional expertise regarding the topic of their testimony, *i.e.*, cost of capital or utility capital structure. (5452). While such candor may be refreshing, since these witnesses have offered no independent evidence and have limited the rate of return portion of their testimony to approximately two pages, the Commission must reject their recommendations.

The testimony offered by the NYPA Panel is similarly defective. The NYPA Panel offers no evidence that they independently developed any samples of comparable risk companies, or performed a DCF analysis, CAPM analysis, risk premium analysis, or comparable earnings analysis, to arrive at their recommendation. (2666RR). In fact, the following two sentences constitute the sum total of their rate of return "analysis":

> The average allowed return in the past 1-1/2 years for the electric utility industry nationwide has been 10.3%, according to statistics published by the Edison Electric Institute in its "EEI Q2 2007 Financial Update, Rate Case Summary". See Exhibit___ (NYPA-2), page 15. The level allowed to Con Edison should be well below that, and the 9.5% to which we understand the Company agreed in the recent gas case would appear to be a reasonable starting point.

(4624).

Aside from the factual error contained in this statement,[168] such general observations, devoid of supporting evidence, hardly provide a reasoned basis on which the Commission can establish the Company's cost of equity.

9. Cost of Long-Term Debt, Preferred Stock, and Customer Deposits

In contrast to the cost rate for common equity, the Staff Finance Panel agreed to use the cost rates for long-term debt, preferred debt, and customer deposits proposed by the Company's Accounting Panel in Exhibit 90. (3726). No other party to this proceeding has challenged these cost rates.

10. Overall Rate of Return

The rate of return is determined by calculating the return on equity and weighing it, along with the cost of debt, according to the Company's capitalization structure. Based upon the capital structure and cost rates set forth in the testimony of Company witnesses and as discussed

[168] The ROE reflected in the most recent Company gas rate plan is 9.7%, not 9.5%, which the NYPA Panel acknowledged during cross-examination (4661).

above, the Company's overall rate of return should be as set forth below:

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
RATE OF RETURN REQUIRED FOR THE RATE YEAR
TWELVE MONTHS ENDING MARCH 31, 2009
(Thousands of Dollars)

Company September 2007 Update	Amount	Capital Structure Ratio	Cost Rates %	Weighted Average Ratio
Long Term Debt	$ 8,667,883	49.03%	5.90%	2.89%
Customer Deposits	232,855	1.32%	3.65%	0.05%
Total Cost of Debt	8,900,738	50.35%		2.94%
Preferred Stock	212,563	1.20%	5.43%	0.07%
Common Equity	8,565,112	48.45%	11.50%	5.57%
Total Cost of Capital	$ 17,678,413	100.00%		8.58%

V. DEPRECIATION AND AMORTIZATION

A. The Company Has Proposed Reasonable Depreciation Changes

The Company, through the testimony of its witness Mr. Hutcheson, proposes to update the average service lives of twelve of the Company's primary plant accounts or sub-accounts, with eight changes toward shorter lives and four toward longer lives. (653-654). Reflecting the Company's recent removal cost experience, he also proposes to change the majority of the Company's primary plant accounts or sub-accounts toward higher negative net salvage factors. (660-661). In developing his recommendations, Mr. Hutcheson relied primarily on current plant mortality studies ("Current Plant Mortality Studies"), set forth in Exhibit 41, of which four of the production plant studies were adjusted to remove the actual historical retirement experience applicable to plant transferred from electric to steam. (725). In the interests of clarity and completeness, Mr. Hutcheson included within Exhibit 41 both the production plant studies as adjusted for the retirement exclusion, and the unadjusted studies containing the "terminated exposure" adjustment described in his direct testimony. (659). The cumulative effect of Mr.

Hutcheson's proposed changes would increase the Company's annual depreciation expense by approximately $48 million, excluding the effects of the reserve variation amortization.

In testimony sponsored by Mr. Rieder, Staff takes exception to six of the Company's proposed average service life changes and two of its proposed net salvage changes. (3925; 3939). In total, Mr. Reider would decrease the Company's proposed depreciation expense by $16.4 million annually. The City and Westchester each propose to remove net salvage from the Company's annual depreciation rate and replace it with an amortization based on a 10-year rolling average of the Company's past actual experience. (4476-4477; 5458). Finally, both CPB and NYPA propose to eliminate all depreciation rate changes. (4689; 4641). For the various reasons set forth below, the Commission should reject all of these proposals and adopt the Company's proposed depreciation changes.

B. <u>Staff's Contested Average Service Life Selections</u>

For two of the contested average service life selections, Staff agrees that a shorter average service life is appropriate, but contends that the Company has lowered the lives too far. Concerning *Account 9514 - Structures and Improvements*, Mr. Hutcheson proposes to lower that life, from 65 years to 40 years. Mr. Rieder proposes to lower the life as well, but only to 55 years. The differences on this life are two-fold. First, Mr. Hutcheson's interpretation of the plant mortality study indicates that the life has dropped considerably. (694). The recent rolling bands for the second and third degrees indicate service lives of 12 and 13 years. In addition, degrees 2 and 3 of the shrinking bands for this account indicate trends toward significantly lower lives.

Mr. Hutcheson bases his analysis primarily on the Current Plant Mortality Studies, in this case study number 055144. In contrast, in developing his recommendations, as he

acknowledged under cross-examination, Mr. Rieder relies on the Current Plant Mortality Studies, as well as two other outdated plant mortality studies. (3951-3952). Specifically, in addition to the Current Plant Mortality Studies, Mr. Rieder utilizes Mr. Hutcheson's plant mortality studies (also set forth in Exhibit 41) that were *not* adjusted to remove the actual historical retirement experience applicable to plant transferred from electric to steam ("Unadjusted Plant Mortality Studies"), as well as the Company's 2002 plant mortality studies ("2002 Plant Mortality Studies") produced in its last electric base rate case (*i.e.*, Case 04-E-0572). During cross-examination, Mr. Rieder admitted that he relies equally on all three plant mortality studies. (3952-3953).

As noted in Mr. Hutcheson's rebuttal testimony, Mr. Rieder erred in relying on plant mortality studies other than the Current Plant Mortality Studies. (6943). These studies are inherently inaccurate as they fail to exclude the major retirement history related to the transfer of electric steam production plant from the Company's electric department to its steam department. (656-657). By basing much of his analysis on outdated, inaccurate plant mortality studies, Mr. Rieder fatally undercuts his own recommendation regarding *Account 9514 - Structures and Improvements*.

Regarding *Account 9526 - Miscellaneous Power Plant Equipment*, Company witness Hutcheson proposes to decrease the life from 50 to 40 years. Staff witness Rieder again agrees that the life should be lower, but only to the extent of moving to a 45-year life. Mr. Hutcheson's analysis of the statistical study fully supports his 40-year proposal. (694-695). The more recent rolling bands for study number 055264 for the third degree indicate lives that are generally below the existing average service life. The widest shrinking bands indicate a life for the first and third degrees of 31 and 33 years respectively. Notably the third degree, which is the degree

of best fit, trends toward lives that are significantly below the Company's proposed 40-year life. Moreover, Mr. Hutcheson again limits his analysis to the Current Plant Mortality Studies, in this case study 055264. In marked contrast, Mr. Rieder again improperly relies on the Unadjusted Plant Mortality Studies.

For *Account 9534 - Station Equipment* and *Account 9565 - Line Transformers (Overhead)*, Mr. Rieder disagrees with the Company's proposal to lower the lives for both of these accounts by five years. In his view, these changes are premature and he recommends that the lives remain unchanged. For *Account 9534 - Station Equipment*, Mr. Hutcheson proposes to lower the life from 50 to 45 years, while Mr. Rieder proposes to leave it unchanged at 50 years. As noted in his rebuttal testimony, Mr. Hutcheson's review of study number 055341 indicates that the recent rolling bands for the second and third degrees show lives below the current 50-year life. (696). The widest shrinking bands for the third degree, the degree of best fit, indicate 46 years and do not vary much from that life. The combination of the indications evidenced by the third degree shrinking bands and the indications seen in most of the recent rolling bands justify reducing the service life of this account to 45 years.

For *Account 9565 - Line Transformers (Overhead)*, Mr. Hutcheson proposes the life be set at 30 years instead of the 35-year life currently in effect. Mr. Rieder proposes to leave the life unchanged. Mr. Hutcheson's analysis of study number 055652 indicates that the most recent rolling bands for the first and third degrees evidence lives that are slightly lower than the existing 35-year service life. (696-697). The widest shrinking bands for degree 1, the only degree with all bands fit, indicate a 34-year life but trend toward lower lives. This trend toward lower lives, in conjunction with the lower lives indicated by the rolling bands, justifies the need to lower the life for this account.

For *Account 9567 – Underground Services*, and *Account 9576 - Underground Street Lighting and Signal Systems*, Mr. Hutcheson proposes to leave the existing service lives unchanged at 70 and 65 years, respectively. Mr. Rieder, however, proposes the lives for both of these accounts should be increased by five years. Mr. Hutcheson elects to leave the lives unchanged because infrastructure work being performed on the underground system will result in retirements in the near future that will tend to decrease lives as we move forward in time. Moreover, given the already very long lives for these accounts, it is not appropriate to continue to increase them. (697).

C. <u>Staff's Contested Net Salvage Factors</u>

Regarding the two contested net salvage factors, while the Company and Staff both agree that the net salvage factors should be increased, Staff contends that the Company proposal is excessive. For *Account 9534 - Station Equipment*, the existing rate is 20 percent negative. The Company proposes a 30 percent negative net salvage factor while Staff proposes a 25 percent negative factor. As noted by Mr. Hutcheson, the study data supports the Company's proposal. (698). The shrinking bands trend toward increased negative percentages, with the more recent shrinking bands all in excess of 40 percent negative. The full experience bands also are trending toward higher negative percentages. The five-year rolling bands likewise trend toward higher negative percentages, and those recent bands are in excess of 40 percent negative. In order to select the proper net salvage factor at a level which will provide for the expected amount of net salvage to be recovered, the totality of the available statistical data in the account must be analyzed. A review of all of that data demonstrates the need to raise the negative rate to that which was proposed by Mr. Hutcheson.

Regarding the other contested net salvage factor, *Account 9554 - Station Equipment*, the existing net salvage factor is 20 percent negative and Mr. Hutcheson proposes to increase the negative percentage to 30 percent. Mr. Rieder agrees that the net salvage factor should be increased, but only to a 25 percent negative rate. Mr. Hutcheson's analysis of the net salvage study for this account validates the need for the move to 30 percent negative. While the full experience percentage is 28.56 percent negative, slightly below the Company's proposal, the recent shrinking bands indicate very high negative percentages. The full experience bands also indicate a trend toward increased negative percentages. As with the previous account described above, the net salvage factor needs to be set at a level that is expected to be in place for the future. As seen in all of the trends within the statistical data, it is proper to fix the net salvage factor at 30 percent negative as proposed by Mr. Hutcheson. (698-699).

D. <u>The City's and Westchester's Net Salvage Proposal</u>

In contrast to Staff's net salvage recommendations which, if erroneous, were at least based on sound statistical studies as presented by Mr. Hutcheson, both the City, through its witness Mr. Arnett, and Westchester, through its witnesses Messrs. Liberty and Radigan, offer similar, transparently results-oriented recommendations that are not worthy of serious consideration. Specifically, both the City and Westchester propose to remove net salvage from the Company's annual depreciation rate and replace it with an amortization based on a 10-year rolling average of the Company's past actual experience. (4476; 5459). As noted by Mr. Hutcheson (701), and echoed by Staff witness Rieder during cross-examination (3948-3950), the Commission should reject this proposed treatment of net salvage since it will create intergenerational inequities. If customers do not pay a small fraction of the future costs of

removal of plant in annual rates, at the end of plant life, future customers that never benefited from such plant would have to pay the entire cost of its removal.

In his rebuttal testimony, Mr. Hutcheson identified multiple deficiencies with the City's and Westchester's net salvage proposal. (701-702). In addition to fostering intergenerational inequities, their proposal violates basic principles of cost causation and economic soundness. That is, customers who benefit from the electric infrastructure should pay for its entire cost, including applicable removal costs. Net salvage occurs when an asset is retired; it is measured by the dollars realized from the sale or scrap disposal of the asset less its cost of removal. The purpose of a net salvage factor in depreciation rates is to properly reflect, over the life of the plant, the anticipated cost of its retirement, including the cost of removal. This approach, advocated by Mr. Hutcheson, fairly provides for payment by current customers of a small portion of the negative net salvage each year over the life of the plant, while that plant is providing service and benefits to those same customers today.

Moreover, the City's and Westchester's net salvage proposal suffers from a more practical flaw. Specifically, the annual net salvage expense afforded under the City/Westchester proposal is woefully inadequate to cover the amounts the Company has expended over the past few years on net salvage. (717-719). In fact, both Mr. Arnett and the Westchester Panel are reduced to employing a ten-year average in order to make it appear that their proposals will allow a barely adequate recovery level of the Company's net salvage expenditures. (718). By failing to allow the Company at least such current recovery, the City and Westchester proposals serve to increase depreciation related costs that will need to be recovered in the Company's next electric base rate case and well beyond.

On cross-examination (*see*, Exh. 297; 4530), Mr. Arnett acknowledged that the Company's current treatment of net salvage "is widely used in the utility industry." Apparently, Mr. Arnett has no deep seated theoretical or philosophical opposition to the Commission's treatment of net salvage. In fact, under cross-examination, Mr. Arnett stated that he is not suggesting that the Commission ought to change its practice with respect to net salvage for utilities other than Con Edison. (4531). The fact that a handful of jurisdictions (*e.g.*, Pennsylvania and New Jersey) may expense net salvage, as alleged by Messrs. Liberty and Radigan (5458), hardly constitutes a compelling rationale for jettisoning the Commission's longstanding treatment of net salvage. For all these reasons, the City's and Westchester's net salvage proposal must be rejected.

E. <u>CPB's and NYPA's Proposal</u>

Finally, CPB witness Elfner and the NYPA Panel propose to eliminate all depreciation rate changes. Neither proposal is based on any methodological disagreement with Company witness Hutcheson. Rather, in Mr. Elfner's view, the Company's need for depreciation-related changes proposed in this case is not sufficient to justify the resulting rate increase for consumers. (4690). The NYPA Panel is less clear in their arguments against changing depreciation rates, but they are clear in their conclusion that the Commission should reject all changes to depreciation rates. (4641). In response to both parties, as discussed above, Mr. Hutcheson has demonstrated a need to increase the Company's depreciation rates in this proceeding. Mr. Hutcheson's plant mortality studies filed in this case (see, Exhibits 41 and 42) support a finding that current service lives and net salvage factors are not adequately providing for the proper levels of depreciation expense. Those studies provide a sound and reasonable basis for the Commission to approve the Company's proposed depreciation changes. The fact that the Company's proposed revenue

requirement may exceed what Mr. Elfner considers reasonable provides no basis for disallowing the Company's proposed depreciation rate changes.

VI. SALES FORECAST

The Company's Forecasting Panel – Margaret Lenz, Department Manager of Revenue and Volume Forecasting, Patrick Hourihane, Section Manager of Electric Revenue and Volume Forecasting, and Hock Ng, Senior Planning Analyst – testified regarding the Company's forecast of electric sales volumes, delivery revenues and system sendout. (529-551, Exh. 25, Exh. 26).

A. Development of the Forecast

1. Sales Volume Forecast

The electric sales volume forecasts were developed by service class ("SC") using various econometric and time series (Box-Jenkins) models. (533). The econometric models used to forecast electric sales volumes for SCs 1, 2, 4, 7, 8 and 9 were developed on a quarterly basis and included weather, economic, and dummy variables as explanatory variables. Heating and cooling degree days were included in all models to account for sales variations due to differences in weather conditions. The key economic variables, real electric price, number of customers, and private non-manufacturing employment, were included where appropriate to account for the impact of economic conditions.[169] (533-535). For SCs 12 and 13, monthly Box-Jenkins models including only weather variables were used. (535-537). Time series models were also used for NYPA sales volumes. EDDS volumes were forecasted on a deterministic basis. (540-541). In reviewing the Company's models, Staff noted that the Company's econometric models "are generally acceptable under the econometric standards." (3895-3896).

[169] Dummy variables were also included in the SC 1 and SC 4 models to account for impacts of special events. (533-535).

The billable demand forecast for each of the commercial classes (SCs 4, 8, 9 12, and 13) was then calculated as the ratio of the forecasts for energy volume and the average hours use. (544). The average hours use was forecasted based on a detailed analysis of the relationship between historical sales volumes and billable demand. *(id.)*

Adjustments were then made to the model forecast to account for savings from the Demand Side Management ("DSM") program proposed in this filing. The cumulative savings were provided by Company witness Craft. The Forecasting Panel deducted the energy and demand savings that were already reflected in the forecasting model results from the cumulative savings provided by Ms. Craft. Thus, only incremental savings from the DSM programs were manually deducted from the model forecasts. (Exh. 39).

2. <u>Delivery Revenue Forecast</u>

The delivery revenues were estimated by month and by service classification based on the resulting sales and demand forecasts. (543). For each of the energy only classes (SCs 1, 2 and 7), a pricing equation was developed by correlating historical average delivery revenue of the class to historical volume of the class, the number of billing-days and summer/winter rate differentials, if applicable, for the period January 2006 through December 2006. *(id.)* For each of the commercial classes (SCs 4, 8, 9, 12 and 13), where energy and demand charges apply, a demand pricing equation was also developed by correlating historical average delivery revenue of the class to historical billed demand of the class, the number of billing-days and summer/winter rate differentials, if applicable, for the period January 2006 through December 2006. *(id.)* The energy delivery revenues for commercial classes were based upon pricing equations similar to those developed for the energy only classes. (543-544).

As for NYPA delivery service revenues, they were estimated by applying monthly average demand rates to the estimated billable demand. *(id.)* The estimated monthly demand rates were based upon the actual 2006 average demand rates adjusted to reflect the rate increase that became effective on April 1, 2007. *(id.)* Monthly billable demands were projected using historical growth patterns. (545).

3. <u>Sendout Forecast</u>

An econometric model was used to forecast the franchise area sendout on a quarterly basis. (545). In this model, the Forecasting Panel included weather variables in terms of heating and cooling degree days to account for variations in weather conditions. *(id.)* Three economic variables – real electric price, total non-manufacturing employment and the number of customers – were also included in the sendout model. *(id.)* The sendout forecast reflected the impact of DSM programs in the same fashion as reflected in the sales volume forecast. (546).

The quarterly sendout forecast was further segregated into monthly forecasts for use by Company witness Holtman in forecasting fuel costs. (547) Monthly sendout figures were derived by reflecting the patterns of historical weather-normalized monthly sendout figures. *(id.)* (547).

4. <u>The Company's Forecasts</u>

The Company's Forecasting Panel projected the sales volumes for the three rate years to be 58,541 GWHs, 58,980 GWHs and 59,501 GWHs respectively. (542). Forecasts of the franchise area sendout for the same periods are 62,825 GWHs, 63,570 GWHs and 64,359 GWHs, respectively. (547).

B. Testimony of Others Regarding the Forecast

Staff, through its witness Anping Liu, made adjustments to the Company's sales forecast, and NYC, through its witness Harvey Arnett, commented on the sales forecast.

1. Staff

Staff witness Liu proposed an upward adjustment of about 220 GWHs to the Company's sales forecast. (574). This increase resulted from the following adjustments:

a. Mr. Liu introduced a real personal income variable as an independent variable in the forecasting models for SCs 1 and 7.

b. Mr. Liu removed the dummy variable in the third quarters of 2005 and 2006 in the SC 1 forecasting model.

c. Mr. Liu increased the forecasted number of customers for SC 1, 2 and 7 by 1892, 553 and 177.

d. Mr. Liu increased the Company's normal cooling degree days ("CDD") by including CDD for the months of April, May, November, and December.

e. Mr. Liu replaced price deflators used to obtain the real price of electricity. (575).

Additionally, the Staff Rate Panel provided a "price out" to incorporate the five adjustments to the Company's forecast listed above. Originally, Staff determined that this level of sales equated to an increase of $18.4 million in the Company's delivery revenue forecast, which it also reflected as a decrease to the Company's total revenue requirement. (586-590). The Company's rebuttal testimony explained that the sales and demand forecasts that Staff applied to the pricing equations were incorrect in that the Staff Rate Panel applied a forecast of 10 GWH higher than Mr. Liu suggested, and that Staff applied certain allocation percentages and the DSM adjustments in incorrect order. *(id.)* The revision of the Staff Rate Panel testimony regarding the allocation percentages and treatment of DSM is now in line with the Company's method. The revision decreased the sales forecast variance between Staff and the Company to

about 213 GWH, and the revenue forecast variance to $12.2 million from the variance of $18.4 million in Staff's original position.

2. NYC

NYC witness Arnett questioned the Company's treatment of future DSM savings in its forecast. Mr. Arnett considered the Company's adjustment to the sales forecast to remove the future impact of DSM as "a double count of the impact." (4471). Mr. Arnett argued that since the historical data contained DSM impacts of prior DSM programs, the forecasts from the sales models would already include the DSM impacts.

3. Discussion of Issues

Both in rebuttal testimony and through cross-examination, the Company explained the reasons that both Mr. Liu and Mr. Arnett were incorrect in their assertions and adjustments.

a) Personal Income Variable

Regarding Staff witness Liu's recommendation that the residential forecast for SCs 1 and 7 should have a personal income variable in its sales forecasting model, he failed to note several important facts about the derivation of such a variable. To begin, while the Company could agree that a real disposable income variable is "theoretically sound" and would be a good variable to include in the residential model, it has not done so because the required data are not available on a quarterly basis. (576; 594-595). In cross, Mr. Liu conceded that personal income data is only available on an annual basis, that it is not available quarterly and that there were many different methodologies to derive this variable from the annual information. (3911-3912, Exh. 267). Data on personal income and population are available only on an annual basis and with up to a two-year lag. (576). These realities of the existing data necessitate the construction of the quarterly historical data for Per Capita Real Income, which leads to the introduction of

estimation errors in two ways. *(id.)*. First, the method for converting the annual figures into quarterly figures is arbitrary and may not reflect the actual quarterly figures. *(id.)*. Second, the actual annual data is available only through 2005, while the sales data in the forecasting models are actual sales volumes for the period from the first quarter of 1981 through the fourth quarter of 2006. *(id.)*. Hence, the data on real income for all of year 2006 has to be estimated. *(id.)*.

This estimation creates an accuracy problem for the model, matching historically estimated personal income and actual sales volumes and not knowing if the estimated personal income is correctly matched with the sales reaction.

Most important, Mr. Liu also agreed that the development of a personal income variable does not take into account the pattern of when the personal income is actually received. (3912). In fact, the Company's Forecasting Panel discussed this issue under cross-examination, stating "what we are saying is that the quarterly pattern may not be representative of how the quarterly sales came in. It may not allocate the annual data correctly, saying that quarterly personal income had the effect on that quarterly sales data. That's what I mean by the accuracies. We don't know if that personal income on a quarterly basis is accurate or not." (595). Because of these issues in estimating quarterly personal income, the Company has not employed a personal income variable in its forecasting models.

Mr. Liu has not demonstrated how these issues may be overcome. Therefore, the use of a personal income variable in the SCs 1 and 7 models should be rejected.

b) <u>2005-2006 Dummy Variable and Appliance Saturation Levels</u>

The Company's Forecasting Panel defined the dummy variable D2005603 as taking on the value of one in the third quarters of 2005 and 2006 and explained that its inclusion in the sales volume forecasting model for SC 1 was intended to capture the effects on SC 1 sales of the

unusually warm summer of 2005 and the unusually hot days during August 2006. (Exh. 28). To demonstrate the necessity for including this variable, the Forecasting Panel provided an analysis using charts of daily weekday sendout against the daily number of CDDs that show the exceptional response of sendout to CDD in the presence of high CDD days in the third quarters of 2005 and 2006. (Exh. 29).

Staff witness Liu concluded that this variable should not have been included after drawing the wrong conclusion from two observations he made. Mr. Liu first observed that SC 1 sales comprise 26 percent of the Company's sendout. He then noted that the Company's models for the other major service classes did not include such a dummy variable. (3898-3899). He went on to incorrectly interpret these two limited pieces of information, and consequently rejected the inclusion of the dummy variable in the SC 1 model.

Mr. Liu apparently interpreted the absence of the dummy variable from the other SC models as indicating "that the impact of the hot weather in 2005 and the hot days in 2006 can be explained by the weather variable included in the model." (3899). However, this interpretation fails to consider the fact that the response of sales volume to weather varies across the different service classes. Mr. Liu conceded that Staff's own sales volume forecasting models show that SC 1 customers are more responsive to changes in the weather than commercial customers. (3913). With greater sensitivity to weather, the reaction of SC 1 customers to the unusual weather in the third quarters of 2005 and 2006 was exceptional while the reaction of other customers was not so extreme as to justify including the dummy variable in the other service classes. In fact, since SC 1 sales comprise only about 26 percent of the Company's total sendout, the response of SC 1 sales was exceptionally large for sendout to show such a significant increase. In contrast, the sales levels in the other service classes did not show enough

of an increase to merit including a dummy variable to remove the weather effects in those models. (578).

While Mr. Liu provided an analysis purportedly to support his position to remove the dummy variable, he based his conclusion on another incorrect assumption. (3900-3902). In this analysis, Mr. Liu re-estimated the SC 1 sales volume forecasting model on a shortened sample through the fourth quarter of 2005, and used it to provide ex-post forecasts of sales in the third quarter of 2006 under three scenarios. (3900). In the first scenario, he included the dummy variable and assigned it to take a value of 0 in the third quarter of 2006. In the second scenario, he also included the dummy variable, but assigned it to take a value of 1 in the third quarter of 2006. In the third scenario, he excluded the dummy variable from the model. (3900-3901). His results show that the first scenario produced the forecast that is furthest from the actual sales, while the second scenario produced the forecast that is closest to the actual sales. (Exh. 264). He inferred from these results that the Company's approach produced the "worst" forecast. (3901). This inference is based on Mr. Liu's assumption that the first scenario in his analysis represents the Company's approach. (3900). In fact, it was not the Company's approach. In the Company's rebuttal testimony, the Forecasting Panel demonstrated that Mr. Liu's assumption is wrong. (582). In the Company's forecasting model for SC 1, the dummy variable takes on a value of 1 in the third quarter of 2006 because unusually high CDD days were present in that period. Thus, the Company's approach is represented by the second scenario, not the first, in Mr. Liu's analysis. According to Mr. Liu, the second scenario produced the best forecast. *(id.)*. Mr. Liu's ex-post forecasting results, in fact, showed that the Company's model with the dummy variable to capture the impact of unusual weather in the third quarters of 2005 and 2006 produced a better forecast for the third quarter of 2006 than the model without the dummy

variable. Thus, the Company's approach to using the dummy variable should be retained. *(id.)* Since the sales forecast for SC 1 is based on the forecast period having normal weather, and not unusually hot weather like those experienced in 2005 and 2006, the dummy variable must take on the value of 0 in the forecast period. *(id.)*

Staff also argued that the Company models fail to capture changes in appliance saturation levels and that the increase in SC 1 sales in the third quarters of 2005 and 2006 can be explained by the increase in appliance saturation rates. Staff claimed that there was a surge in the saturation of cooling appliances, like air conditioners, and with more appliances in place for cooling, the demand for electricity was more responsive to weather. (3899). Staff then made a leap of faith in assuming that if customers have more appliances in place, the level of responsiveness will not go down when the weather returns to normal. (3899-3900). Staff's assumptions are incorrect.

Mr. Liu based much of his position on three documents. First, he used Exhibit 265, which was not referred to in the testimony and was not specifically used in the development of Mr. Liu's forecast.[170] (3914-3915; Exhibit 268). This Exhibit is a response to the NYISO that shows how the Company developed its peak load forecast.

Then, he referred to Exhibit 33, which is a Company presentation that was provided to parties in this proceeding, describing the drivers of and issues surrounding the requested rate increase. This presentation stated that the use of air conditioners has increased by 900,000 between 2002-2006. (Exhibit 33). It provided no additional information regarding when or where these air conditioners were installed.

[170] The Company did not make a motion to strike this exhibit, but rather argued that it not be given any weight as it was not used in the sales forecast. (3915).

Finally, on cross, Staff questioned the Forecasting Panel on Exhibit 34, which is a discovery response showing the increase in saturation levels of appliances in recent years. (Exh. 34). This Exhibit shows three years of saturation levels based on surveys performed by the Company.

These documents, either singly or in combination, are insufficient evidence for Mr. Liu's saturation position.

Staff's cross-examination of the Forecasting Panel on the saturation level and the dummy variable is telling because the Panel was unable to agree with Mr. Liu's saturation arguments. (604-619). The Panel explained that the Company's sales forecasting model for SC 1 had the growth rate of sales per customer per billing day as the dependent variable. *(id.)* Hence, the constant term in the model represented the base growth rate of sales per customer per billing day. *(id.)* That is, it captured among other things the average impact of changes in appliance saturation rates over the estimation period. *(id.)* Mr. Liu has not shown that the increase in saturation rate in recent years was any higher than the average growth rate that has been captured in the model.

Staff's attempt to show in Exhibit 33 "for the period 2002 through 2006 there has been growth in the number of room air conditioners of more than 900,000" is misleading. (Exh. 33). The context and reason for the increase in air conditioners were not provided. In fact, this increase may be part of the normal growth in appliances whose impact on the growth rate of sales is captured by the constant term in the Company's model as explained above.

There is also an important distinction between "appliance saturation rate" and usage rate of appliances that Staff failed to recognize. As stated in Exhibit 265, saturation is the percentage of households with an appliance, which is not the same as the percentage of households that are

using the appliance. In its testimony, the Company's Forecasting Panel recognized that when the weather is normal, all the appliances listed in Exhibit 34 will be used by some households. (617). That is not to say, however, that all households that have the appliances will use them during normal weather. (579). The percentage of households that actually use the appliances changes with the weather. During unusually hot summers, like those of 2005 and 2006, the percentage of households using the appliances and the usage of each household may differ so much from normal levels that the weather variables of the sales forecasting models do not adequately account for the sales impact. In such a situation, a dummy variable has to be used to pick up the exceptional sales impact. The dummy variable, D2005603, in the Company's forecasting model for SC 1 is necessary because of such an exceptional usage response in the third quarters of 2005 and 2006.

Staff has not demonstrated that the third quarter 2005-2006 dummy variables are incorrect. The Company has explained the reasons for them, demonstrated that there is a usage effect on days surrounding hot weather, shown that higher saturation levels do not necessarily result in increased usage, and explained the weather sensitivity of appliances. There is nothing in the record that shows that the inclusion of this variable was incorrect. As such, Staff's contention regarding saturation levels must be rejected, and the Company's use of the dummy variable, D2005603, must be allowed.

c) <u>Number of Customers</u>

Staff witness Liu testified that he had superior methods for forecasting the number of customers for SCs 1, 2 and 7. (3915-3906). For SC 1, he proposed an alternative to the Company's Box-Jenkins model, and for SCs 2 and 7, he suggested using Box-Jenkins models in place of the Company's three-year averages of historical growth rates. (3906).

Mr. Liu claimed that his model for forecasting the number of SC 1 customers is an improvement over the Company's model in terms of both goodness-of-fit and forecast performance. (3906). His claim is not supported by evidence. Mr. Liu admitted that he used R square as the measure of goodness-of-fit. (3913). Econometric theory shows that R square is not a valid measure to compare the fit of alternative models when the dependent variables of the models are not identical as is the case between the Company's model and the Staff's model. Exhibit 27 demonstrates that other measures of goodness-of-fit, such as the loglikelihood, the Akaike Information Criterion, and the Schwarz Criterion, which are valid for comparisons between models with different dependent variables, all point to the Company's model as having the better fit. Exhibit 27 also shows that when the two models are estimated using data from the first quarter of 1981 through the fourth quarter of 2003, the Company's model provided forecasts that are closer to the actual values in the period from the first quarter of 2004 through the fourth quarter of 2006. Thus, based on the evidence submitted, the change in the forecast of the number of SC 1 customers recommended by Staff should be rejected.

In addition, the changes in the forecasts of the number of SCs 2 and 7 customers proposed by Mr. Liu should also be rejected as he did not provide any evidence that his forecasts for the number of SCs 2 and 7 customers are any better than the Company's forecasts.

d) <u>Increase to Cooling Degree Days in non-Summer Months</u>

Mr. Liu increased the level of sales by including normal CDDs in the months of April, May, November and December in the forecast. (3903-3905). He argued that the Company should be using the actual 30-year average of cooling degree days for all months instead of only the months of May through October. *(id.)*

In rebuttal and on cross, the Forecasting Panel explained that CDDs are used as a measurement to capture the impact of weather on customers' use of air conditioning appliances, normally in the months of May through October. (585). The Forecasting Panel agreed that there could be CDDs in April but explained that "the incorporations of these days in the normal is inconsistent with the practice of the experts at the National Weather Service Bureau." *(id.)*. This is because the 30 year average is smoothed so that the normal CDD shows a gradual increase as we enter the summer and a gradual decrease as we enter the fall. *(id.)* On cross, the Forecasting Panel explained that when considering April's CDD, one must consider the reasonableness of applying a cooling factor and incorporating it to normalize sales volumes. Also, on cross, the Forecasting Panel stated that the CDD variable is developed by taking the average of the 24 hour average of the dry and 24 hour average wet bulb temperatures and subtracting the CDD temperature reference of 57.5° F. (620). Mr. Hourihane explained the calculation of the cooling degree day variable.

"So as an example, if you had a day that rained and the temperatures won't vary that much, goes from 58° F in 24 hours up to 62° F. Dry bulb would be 60° F 24 hour average. If it rains all day and is overcast and misty your wet bulb would also be the same temperature, an average of 60° F. So in that case you would have 60 minus 57.5 give you 2.5 cooling degree days for the day." (620-621).

Mr. Hourihane continued that "with the example I just gave you on calculating cooling degree day with the dry bulb temperatures, dry bulb temperatures are only used on the heating degree days. It's possible to have heating and cooling on the same day. The temperature variable for heating degree days is 62° F. So, in that case you take around 60° F on the dry bulb, take it away from 62° F and had two heating degree days." (622-623).

Mr. Hourihane also stated that with April cooling degree days, "we look at it as you are coming out of the winter." (623). "You have the heating unit on." *(id.)* "Businesses again will have their heating units on." *(id.)* "As you get cooling degree days, if it flips back and forth, the buildings themselves take a couple of days to heat up before you are going to require any kind of cooling." (624).

The Forecasting Panel has explained why there is no need to increase the normal CDDs by including the April CDDs. Since the average temperature is lower in March, November and December, there is no reason to include CDDs outside the May through October period. As such, the adjustment of normal CDDs should be rejected.

e) <u>Price Deflators</u>

Mr. Liu made a change to the price deflators that were used in calculating the real prices of electricity that were in turn used as explanatory variables in the quarterly sales forecasting models. The Company had used the Consumer Price Index for Urban Wage Earners and Clerical workers ("CPI-W") for all service classifications. (586; 3906). Mr. Liu replaced this index with the Consumer Price Index for all Urban Consumers in calculating the price of electricity for residential customers. He also replaced CPI-W with the GDP Price Index in calculating the price of electricity for commercial and industrial customers. (3907-3908).

The Company agreed to this proposal but simply noted that the change to the sales forecast because of this adjustment is minimal. (586).

f) <u>DSM Forecast</u>

City witness Arnett is the only witness in these proceedings who questioned the Company's treatment of the estimated effect of the DSM savings. Staff accepted the Company's

treatment of these savings and, as mentioned previously, reflected them in its own forecast in the same fashion as reflected in the Company forecast. (Exhibit 362).

Mr. Arnett claimed that "because DSM has dampened sales over time, the effect of the sales models is to dampen the coefficients for the model's independent variables." (4472; 591). To support this assertion, he conducted an analysis where he estimated a "simplified" version of the Company's sendout model using three different sendout data series. The first sendout series was the actual sendout and the other two series were artificially constructed, using hypothetical assumptions. The second sendout series was based on an assumed "compound growth rate in DSM of 0.2 percent per year" (4473; 591), while the third sendout series was based on "a variable impact of DSM, ... 0.1 percent through 1990 and 0.3 thereafter, ... compounded annually." (4474; 591).

The Company does not agree with Mr. Arnett's analysis because it is based on hypothetical data that do not reflect the actual DSM impact of prior DSM programs. (592). Both of the constructed sendout series that Mr. Arnett used assumed that the DSM impact was growing throughout the estimation period. *(id.)* In reality, the Company's sponsored DSM programs do not have a continuously growing impact. *(id.)* For example, once a light bulb or a refrigerator has been exchanged for a more energy efficient model, the program provides energy savings, but these savings from the one light bulb or refrigerator do not grow over time.

Another flaw in Mr. Arnett's analysis is that it uses a simplified regression model that misses an important part of the Company's sales forecasting models, the ARIMA terms. *(id.)* These terms are important in a forecasting model because they capture the collective impact of factors that are not included explicitly in the model. (2307). The exclusion of these terms may

lead to biased standard errors in the model. (2308). As such, the results of Mr. Arnett's analysis are inaccurate and not representative of reality and should be rejected.

More importantly, the Company's adjustments to the sales forecasts only reflected incremental savings. The savings provided by Company witness Craft relate primarily to new DSM programs proposed in this filing. For the one program that had savings in the historical period reflected in the model forecast, the Company discounted the savings provided by witness Craft by the amount of savings already achieved. (Exh. 39).

For these reasons, the DSM savings as reflected in the Company's forecast must be accepted. The Company has demonstrated that its forecast is proper, and the Commission should reject the adjustments made by Staff and NYC.

VII. DEFERRAL ACCOUNTING AND RECONCILIATION

A. Reconciliation Mechanisms

The Company proposes to continue the reconciliation of certain expenses outside of its direct control that have typically been the subject of reconciliation mechanisms included in rate plans adopted by the Commission and are the subject of reconciliations under the Company's current rate plans, with some modifications. The expenses at issue are property taxes, interference costs, and environmental remediation costs.[171] The Company discusses these mechanisms in the context of its three-year rate plan proposal and also proposes that these

[171] The Company is currently subject to the Commission's Pension Policy Statement and its reconciliation provisions. Moreover, the 2005 Rate Plan contains the following provisions (2005 Rate Plan Order, App. A, p. 13):

> The Company agrees that, as a condition for being permitted to implement the provisions of the Pension Policy Statement, it will not, during the Electric Rate Plan or thereafter, without Staff's prior concurrence, seek approval or authorization from the Commission to deviate from the Pension Policy Statement for electric corporations (emphasis added).

Accordingly, the Company is obligated to continue to reconcile such costs.

mechanisms be implemented if the Commission makes a one-year rate determination. (2429).[172] Also, in the event the Commission rejects the Company's proposal to complete recovery of its deferred WTC-related costs and expenses (addressed in section III of this Brief), and to treat Lower Manhattan interference expenses the same as the Company's other interference expenses, the Company would continue to defer all WTC-related costs above the amounts recovered in rates, including the treatment of WTC deferred capital costs allocated to its electric business in accordance with the Commission's determination in Case 01-M-1958 and, as of April 1, 2005, subject to interest at Con Edison's allowed pre-tax AFUDC rate of return.[173]

As explained by Company witness Rasmussen, these costs are outside of the Company's direct control and could either increase or decrease materially during the first rate year. (2429-2430).[174] The basis for reconciling these costs does not change because base rates may not be set for a multi-year period. Moreover, establishing these true-up mechanisms for a "one-year" rate determination could enable the Company to delay the need for rate relief after new rates take effect. (2430). It is for that same reason that true-up mechanisms in multi-year rate plans normally continue after the end of the last rate year of the multi-year rate plan until base rates are changed by Commission order, as they may be a significant factor in the utility's deciding whether to file or not for a change to base rates.[175]

No party to this proceeding challenges the basic premise for these reconciliation mechanisms (*i.e.*, that they cover costs outside of the Company's direct control). Opposition to

[172] The Company is also proposing to establish reserves for storm and ERRP maintenance expenses, which are addressed in section III of this Brief.
[173] 2005 Rate Plan Order, App I, p. 15.
[174] For that reason, the Company also proposes to continue to true-up for costs resulting from new legislative and regulatory requirements. (2429).
[175] See, for example, section N.2 of the 2005 Rate Plan (2005 Rate Plan Order, App. I, p. 87).

the continuation of these reconciliation mechanisms in the context of a one-year rate determination is discussed below.

Should the Commission determine that additional procedures are necessary to continue one or more of these mechanisms if there is a one-year rate determination (*e.g.*, resetting the forecasted level of property taxes), such procedures can and should be undertaken. Doing so would be consistent with Staff's proposal to continue a RDM established in the context of a one-year rate determination beyond the first rate year. Staff acknowledges that additional procedures would be needed in order to continue that mechanism, although they have not yet contemplated what procedures would be needed. (3975-3976).

1. Property Taxes and Interference Expenses

The Company proposes to continue to reconcile property taxes and interference expenses. However, it proposes to modify the existing reconciliation mechanisms for property taxes and interference costs to eliminate the "deadbands."

The 2005 Rate Plan provides for the Company to true-up its actual expenditures for property taxes and interference expenses[176] as measured against forecasted expenses for these categories of costs, subject to a 2.5 percent "deadband" above and below the targeted amounts. To the extent that actual expenditures are within 2.5 percent of the targeted amounts, there is no reconciliation. (2432).

As Mr. Rasmussen explains, these costs are outside the direct control of the Company in that they depend upon the actions of various government entities. (2432). Accordingly, a

[176] For purposes of clarification, the current reconciliation mechanism for interference is for O&M expenses, excluding Company labor, and not for capital interference expenses. *See* 2005 Rate Plan Order, App. I, section D. 2, pp. 10-11). Although the gas rate plan approved by the Commission in Case 06-G-1332 contains a separate reconciliation mechanism for capital interference costs, the Company is not proposing in this case a reconciliation mechanism for capital interference costs. Case 06-G-1332, Order Adopting in Part the Terms and Conditions of the Parties' Joint Proposal, September 25, 2007 (hereinafter "2007 Gas Rate Plan Order"), App. I, pp. 14-15.

deadband does not provide the Company either an incentive or a disincentive to reduce a cost over which it has no direct control, but merely results in either the Company or its customers receiving a windfall of up to 2.5 percent of the targeted amounts at the expense of the other. (2432).

The Staff Accounting Panel proposes that there be no property tax reconciliation mechanism. (3611). For interference expenses, the Staff Accounting Panel proposes to modify the currently effective reconciliation mechanism so that expenses are reconciled only to the extent actual expenses are below forecasted amounts, which Staff proposes be deferred for future refund to customers. (3592-3593). Implicit in Staff's proposal is the elimination of the existing 2.5 percent deadband.

The basis for Staff's proposal is the magnitude of the Company's rate request, the fact that forecasted amounts for interference are greater than the actual average interference expense over the last four years, and to encourage the Company to coordinate its interference expenditure work closely with the New York City "in order to ensure efficient use of resources." (3592-3593). None of these reasons establishes a basis for accepting the Staff proposal or rejecting the Company's proposal.

First, the magnitude of the rate increase should have no bearing on the reasonableness and propriety of a reconciliation mechanism for costs outside of the Company's control. Ultimately, the rates that will be established in this proceeding will be the result of a Commission determination that such rates are just and reasonable and necessary for the Company to maintain safe and reliable service to its customers. Moreover, a fair and equitable reconciliation mechanism, that is based upon a reasonably-derived targeted level of expenses,

protects customers from overpaying costs to the same extent that it protects the Company from undercollecting its costs.[177]

Second, with respect to interference costs, the testimony of both Staff and the Company establishes that the Company bases its forecast upon information provided by New York City, which information routinely changes materially throughout each calendar year and over which the Company has no control. (1186-1187; 1197; 3585-3586). In recognition of the volatility of the City's forecasts, but in reliance on the most recent information available from the City, as discussed in section III of this Initial Brief, the Company accepted an adjustment from Staff to reduce its forecast of interference O&M expenses by approximately $11.6 million for the rate year. (Exh. 241, Schedule 8, Page 2 of 5, Adjustment 2h). However, it would be neither reasonable nor equitable to establish a target at the low end of a reasonable range of forecasted expenditures and then subject the Company to the risk of expenditures above the forecasted amount while protecting customers for expenditures below the forecasted amount. As discussed below, it would be similarly inequitable to establish a target of property taxes at the low end of a reasonable range of forecasted expenses without providing for reconciliation of such expenses.

Third, as to the need to encourage the Company to work closely with New York City to minimize interference expenditures, Company witness Gencarelli testified as to the efforts undertaken by the Company to minimize such expenses. (1197-1199). Moreover, Staff acknowledged that it had no information that the Company is not working closely with the City to coordinate its interference work to "ensure efficient use of resources." (3656). Staff further acknowledged that four members of the Staff Accounting Panel filed testimony in the Company's recent gas rate proceeding (Case No. 06-G-1332) in support of a bilateral

[177] 2005 Rate Plan Order, p. 38.

interference reconciliation mechanism assuming appropriate target levels were set for the rate year. (3657-3658). Staff provides no basis for taking a different position in this proceeding.

Finally, Staff's own proposal for a full reconciliation between actual and forecasted expenses in the context of its one-way true-up mechanism argues in favor of the Company's proposal to eliminate the existing deadbands should the Commission adopt the Company's proposal for a bi-lateral true-up mechanism.

As to property taxes, Staff takes the view that property taxes can be reasonably forecasted and, therefore, there is no need for a reconciliation mechanism. (3610-3611). The facts demonstrate otherwise. For example, Company witness Hutcheson testified that, in one year alone, *i.e.*, fiscal year 2002/2003, the City imposed an 18.5 percent property tax increase (690), demonstrating that Staff's attempt to distinguish the propriety of a reconciliation mechanism as between a one-year rate determination and a multi-year rate plan is without merit. Moreover, if there were no basis for reconciling property taxes for a one-year rate determination, the property tax reconciliation mechanisms in multi-year rate plans would be limited to the period starting with the second rate year, which certainly has not been the case for the rate plans adopted by the Commission for the Company.[178]

Second, the absence of a property tax reconciliation could unreasonably expose the Company to property taxes higher than they otherwise would be. That is, the taxing authorities may have less reason to limit tax increases if they know that the Company will have to absorb all or some portion of such increases until rates are readjusted.

[178] 2005 Rate Plan Order, App. I., p. 10; 2007 Gas Rate Plan Order, App. I, p. 14.

Finally, should the Commission decide not to adopt a property tax reconciliation mechanism for a one-year rate determination, the forecasted level of property taxes reflected in rates should be based on known facts and circumstances at the time rates become effective.

2. Environmental Remediation Costs

Company witness Price provided the Company's estimates for expenditures on environmental remediation for the linking period and the Rate Year. The bulk of these estimated expenditures is for manufactured gas plant ("MGP") site remediation. (Exh. 21). Mr. Price explained that manufactured gas plants provided energy in the form of combustible gases of varying composition to municipal street lighting systems and to homes and businesses in the areas served by Con Edison from the late 1820s through the early 1960s and that the gas product produced by the plants was used for lighting, cooking and heating. (0459). He further explained that the plants handled significant quantities of feedstock materials, by-products, and residuals contained organic and inorganic chemical constituents that are now considered to be hazardous substances under federal and state laws and regulations that pose a threat to human health and the environment when released to soil or waterways. (460). Con Edison, like most other New York utilities, has entered into consent orders or clean-up agreements to address its MGP sites. (461).

No party opposes the Company's recovery of its actual costs for environmental remediation, including for MGP sites, or to the continuation of a mechanism by which the Company reconciles its actual and forecasted environmental remediation costs.[179] One party,

[179] Staff and CPB do oppose the Company's proposed three-year amortization of its deferred environmental remediation costs, which is addressed later in this section. Also, as discussed in section III of this Brief, CPB does argue that the Company should not reflect any of its forecasted costs in the rates proposed for the Rate Year. For the reasons explained in section III, CPB's position should be rejected. As also discussed in section III, Staff proposed several adjustments to the forecasted amount of MGP remediation costs that the Company proposes to recover in rates, which the Company accepted.

NYPA, opposes the recovery of MGP remediation costs from the Company's electric customers. NYPA's position should be rejected.

The Company has historically treated all of its environmental remediation costs, including costs to clean up former MGP sites, as corporate expenses, which are allocated among the Company's electric, gas and steam businesses.[180] NYPA refers to a Company discovery response (NYPA-49) in which the Company explains that environmental remediation costs are considered to be corporate-wide expenses based upon the Company's understanding of long-standing Commission practice absent circumstances that would justify a different allocation. NYPA neither disputes this long-standing Commission practice nor identifies any circumstances that would justify a deviation from it.

The treatment of these remediation costs as corporate-wide expenses is in line with long-established Commission policy, established by the Commission in its Opinion No. 88-2,[181] where it determined for New York State Electric and Gas ("NYSEG") that these costs should continue to be considered corporate expenses that are allocated among NYSEG's electric and gas customers.[182] The Commission recognized that these costs were a by-product of a service no longer provided by the Company and, more important, that most of the Company's former manufactured gas customers are now the Company's electric customers, relying upon electricity, rather than manufactured gas, for light, heat and cooking.[183] That is, the Commission found NYSEG's electric customers to be "linear descendants" of NYSEG's manufactured gas coal

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[180] See, for example, 2005 Rate Plan Order, App. I, p. 14; 2007 Gas Rate Plan Order, App. I, p. 16; and Case No. 05-S-1376, Order Determining Revenue Requirement And Rate Design, issued and effective September 22, 2006, App. I, p. 18.
[181] Case No. 29541, et al., Proceeding on Motion of the commission as to the Rates, Charges, Rules and Regulations of the New York State Electric & Gas Corporation for Electric Service, Opinion and Order Determining Revenue Requirement and Refunding Excess Earnings, Op. No. 88-2, (issued January 20, 1988).
[182] Op. No. 88-2, p. 22.
[183] *Id*, p. 21.

customers.[184] This rationale is equally applicable today to Con Edison's electric and gas customers.

Finally, it bears mention that a number of the sites subject to remediation currently constitute premises upon which the Company has major electric facilities and major corporate facilities used to provide services to the Company's electric and gas businesses.[185] In this regard, NYPA also ignores the fact that current owners of former MGP sites share cost responsibility for remediation.[186]

Accordingly, NYPA has provided no basis for deviating from the current Commission practice of treating these expenses as common costs and its proposal to shift the entire burden of these costs to the Company's gas customers should be rejected.

3. <u>Transmission and Distribution Capital Expenditures</u>

The Company proposes that there be no reconciliation mechanism for its transmission and distribution ("T&D") infrastructure expenditures. As explained by Mr. Rasmussen, the Company proposes that base rates be set in this proceeding to reflect the Company's forecasted T&D capital expenditures, which would obviate the need for a reconciliation mechanism. (2430).

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[184] *Id*, pp. 21-22.

[185] As shown on Exhibit 18, these sites include the East River Generating Station; the White Plains Substation; the Astoria Site; the East 132nd Holder Station Site (now a dielectric oil cooling plant for the Company's oil-filled electric transmission feeder system); the Zerega Avenue Holder Station Site (now an electric substation); the Farrington Street Gas Holder Site (now the location of one of Company's flush truck facilities); the Farrington Street Gas Works Site (now being used by CECONY as a storage yard to support electric and gas operations); the Saw Mill River Holder Station (now the location of a small electric substation and a CECONY workout location that supports both electric and gas operations); the Greenburgh Gas Holder Station Site (now the location of gas regulator station, an electric substation, and a stores building); the Ossining Gas Works Site (a portion of the site is a Con Edison electric substation); the Rye Gas Works Site (which is now a CECONY service center which support the Company's gas and electric operations and has storage areas for electric equipment, cable, and utility poles); and the East 11th Street Gas Works (which houses a service center supports both electric and gas operations).

[186] 42 U.S.C. § 9607(a); Environmental Conservation Law § 27-1312(3)(a).

Although the Company does propose that the reconciliation mechanism for capital expenditures currently in effect be continued if rates set in this proceeding reflect less than the Company's forecasted T&D capital expenditures (2430), the Company believes that such an outcome in this proceeding would be an unfortunate result, given the extensive testimony by the Company's Infrastructure Investment Panel that the Company's proposed expenditures represent the minimum required to maintain safe and reliable service (2123-2126), and that any slippage in some projects would be balanced by the need to advance others. (2115-2117; 2127). That is, the Company urges that, unlike in the Company's last electric rate proceeding, the rates established in this case should reflect a forecasted level of capital spending on T&D infrastructure, based upon the programs proposed by the Company.

In that regard, should the Commission establish a forecasted level of spending that is lower than that proposed by the Company, the forecasted level of expenditures should be based upon a program-by-program analysis of the Company's proposal, and not an artificially set level of forecasted expenditures as proposed by a number of parties to this proceeding or one that is essentially premised upon a lump-sum slippage adjustment.[187] If the Commission reduces the Company's forecast because it determines that any number of specified projects are not necessary for the Company to meet load growth or maintain safe and reliable service or should be delayed, the Company would not implement such programs or would delay them, thereby obviating the need for the type of reconciliation mechanism adopted in the last case. If, however, the Commission establishes rates in this proceeding that reflects a lump-sum slippage adjustment, the existing symmetrical reconciliation provision should be continued if the

[187] By "slippage adjustment," the Company means that the Commission, on the one hand, recognizes the need for certain projects but, on the other hand, does not provide the Company with the funds necessary to implement such programs because, for example, the Commission is not convinced that the Company will be able to achieve its targeted goals.

Company is expected to complete all work it deems necessary and is, in fact, able to accomplish, in order to maintain safe and adequate service (1970-1971; 1990-1991; 2144-2145).[188]

Although Staff proposes specific adjustments to proposed projects and programs, Staff also proposes an asymmetrical reconciliation mechanism that would reconcile underspending, but not overspending, relative to the forecasted expenditure levels reflected in rates. That is, Staff proposes that the Company's T&D infrastructure spending would be subject to reconciliation at the end of the rate year, as follows:

> If a year end review of these expenditures reveals that the Company has spent less than what it was allowed in rates, we propose that the Company be required to defer such variations between rate allowance and actual expenditures as a ratepayer credit, with interest accruing at the appropriate rate. (3994)[189]

The Company opposes this proposal for several reasons. First, as is the case for a number of other proposals made by various Staff witnesses, the asymmetrical nature of this reconciliation mechanism is unduly preferential to customers and unduly unfair in its treatment of the Company. (1990). If, and to the extent, the Commission determines that such costs should be reconciled, such a mechanism must address the nature of the Company's capital expenditure program in a fair and even-handed manner (*Id*.).

Second, as noted by the Company's Infrastructure Investment Panel, estimates for specific projects and programs can turn out to be understated and new capital projects can become necessary. Absent the ability to defer the necessary overspending, the Company would

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[188] This principle is equally applicable to the Company's O&M budget proposal. As discussed in section III of this Brief, a number of parties have proposed a global reduction to the Company's proposed O&M spending that is not based upon an analysis of the Company's proposed programs. The Company has explained why there are no grounds for the Commission to implement such recommendations. However, should the Commission nevertheless establish the revenue requirement for O&M programs based not on a program-by-program analysis of the Company's proposal (as Staff also recommends), but on a lump-sum slippage adjustment, then the Commission should implement a symmetrical reconciliation provision comparable to that for capital expenditures, if the Company is expected to complete all work it deems necessary and is, in fact, able to accomplish, in order to maintain safe and adequate service.

[189] An asymmetrical reconciliation for T&D capital expenditures is also proposed by CPB (4687). The Company's objections to Staff's proposal are equally applicable to CPB's proposal.

be forced to reduce spending on other projects that are justified whenever it needs funds for an underestimated or new project. (1970-1971).

Moreover, the mechanics of Staff's proposed mechanism are not clear, given Staff's proposals to apply similar "reconciliation-type mechanisms" to specific categories of spending, (such as for example storm hardening and response (4029) and advanced technology (4035)). Staff has not adequately explained how the reconciliations of expenditures for those specific projects would be different from the reconciliation of expenditures for all capital projects in a given year. (1991). Nor has Staff explained why it recommended adjustments to specific projects when, under Staff's reconciliation mechanism, any underspending on those projects will be captured and returned to the ratepayers. (1970).

If, and to the extent, Staff's recommended limitations and reconciliations for specific projects or programs are intended to limit the Company's historical flexibility to reprioritize projects and modify project-specific funding within the context of an overall infrastructure program, Staff's project-specific recommendations should be rejected. The Commission has consistently recognized the need for such flexibility and Staff has not provided any basis for the Commission's imposing any new limitations in this regard. (1991).

B. Deferral Accounting

1. Amortizations

The Company proposed to amortize various deferred costs over a three-year period, whether the Commission makes a one-year rate determination or adopts a multi-year plan. (2435). The Staff Accounting Panel, CPB witnesses Schultz and DeRonne, Westchester and NYPA object to the proposed amortization periods for deferred World Trade Center costs, carrying charges on T&D investments, environmental remediation costs, excess deferred state

income tax and the pass back of various credits. Each proposes to materially extend the proposed period of amortization from the Company's proposal. Specifically, CPB and Westchester recommend a ten-year recovery for deferred environmental costs. (4694; 5465-5466). CPB and Westchester recommend a ten-year recovery for the carrying charges on T&D plant. (4693-4694; 5466). NYPA recommends a 20-year recovery period for deferred environmental costs. (4649). The Staff Accounting Panel recommends continuation of the five-year recovery period for environmental costs. (3597-3598). CPB recommends recovery of deferred WTC costs over a ten-year period. (4699). The Staff Accounting Panel recommends a one-year, *i.e.*, the rate year, return to customers of the deferred excess DC Service Revenues (3557-3558) and Excess Deferred State Income Taxes. (3624-3625). For the latter item, Westchester not only recommends a one-year return of these credits but also recommends the same one-year period for various other deferred credits, such as the gains on the sale of the Company's First Avenue Properties, interest on Federal income tax audit adjustments, the overcollection of NYS tax law changes and the correction of ADR tax amortizations due customers. (5467).

The primary reason given for these proposals is to mitigate the impact of the proposed rate increase on customers. (4649; 4693-4694; 5466). As explained below, the proposed amortization periods should be rejected because they are unreasonably long, bear no relation to the periods of time over which these costs were incurred, impose additional financing costs on the Company, and will result in future rates that do not reasonably reflect current costs. As also discussed below, the proposals to pass back credits over one year are problematic.

First, the Company's proposal to amortize these amounts over a three-year period, whether in the context of a one-year or a multi-year rate determination, is both reasonable and

consistent with historic Commission practice. The proposed amortizations by CPB, Westchester and NYPA are materially outside the normal periods for recovery of these types of costs. (1422-1423).

Second, lengthening of the amortization period would only add to the Company's financing requirements and further weaken its cash flow position (1422) to the ultimate detriment of customers. (4738).

Third, in recommending the recovery of deferred costs over an extended period of five, ten or in some cases twenty years, Staff, Westchester, NYPA and CPB have ignored that the Company proposed passing back over three years the credits that have accumulated over the three years covered by the 2005 Rate Plan to help mitigate the impact of recovering deferred expenditures over a similar period. (1424). Longer term amortizations will result in future rates that do not reasonably reflect current costs.

Finally, minimizing the extent of deferred costs on the Company's books, and more closely matching the amortization periods for both deferred credits and debits, will avoid future rate impacts on customers that reflect, in material part, the reconciliation of past expenses.

Passing back available credits over a period of one year (as Staff and Westchester recommend) would do nothing more than keep rates artificially low for a one-year period. Rates would rise dramatically thereafter as all available credits would have been exhausted. (1423-1424). That is, if the Company was to pass back all credits in the first year and then build up additional deferrals over the next three years, customers in years 2 and 3 would be saddled with paying for these additional costs, as well as the unamortized balance of current deferrals, without the benefit of any offsetting credits from the current rate plan. (1424).

Finally, Westchester recommends, as an additional rate mitigator, that the interest applicable to the deferred T&D capital costs during the proposed 10-year amortization be set at the rate of a 10-year US Treasury bond, which Westchester quotes at "less than 5%." (5466). Westchester's unprecedented and outrageous proposal is not worthy of consideration by the Commission. As explained in section II of this Brief, the Company's T&D capital expenditures were prudently incurred and the Company is entitled to earn a fair and reasonable return on its investments. Westchester offers no reason why it would grant the Company an equity return of 9.7 percent on the Company's total rate base investment (5453), but reduce the carrying charges applicable to T&D capital expenditures incurred during the period covered by the 2005 Rate Plan from 13.95 percent[190] to less than 5 percent.

Moreover, Westchester is disingenuous when it points to the 2005 Rate Plan as an example of how the Company was able to invest over $3 billion in T&D plant despite having received only a modest rate increase. (5446). That modest rate increase, as Westchester well knows, was made possible by moderating rates through various mechanisms that deferred $515 million in rate increases to this proceeding. (2454-2456). These mechanisms also resulted in almost $200 million of deferred carrying charges on T&D capital investments to be recovered from customers. Westchester makes no sense when it praises the modest rate increase in the last rate case, which was kept artificially low only by deferring a large portion of the needed rate increase to this proceeding, and then criticizes the Company for requesting a large rate increase in this proceeding. Nor does it make sense when it arbitrarily segregates a portion of the Company's T&D capital investment and, instead of treating it as other plant-in-service subject to

[190] 2005 Rate Plan Order, App. I, p. 11.

a carrying charge that reflects depreciation expense and a reasonable return, it would treat it as a "government backed security." (5466).

2. Netting of Regulatory Assets and Liabilities

The Company proposes to continue to net outstanding deferred balances at the end of each rate year, whether there is a one-year rate determination or a multi-year rate plan is adopted. (2440-41). Specifically, the Company proposes to continue the mechanism contained in the 2005 Rate Plan.[191]

Company witness Rasmussen testified that the ability to net deferrals has helped simplify the Company's external reporting requirements and made Con Edison's financial statements more meaningful to investors. He explained that when regulatory assets and liabilities are reported on a gross basis, it has the effect of inflating the reported assets and liabilities of the Company and that netting provides an investor with a clearer understanding of the Company's true financial assets and liabilities. (2441).

Staff opposes continuation of the netting provision. However, similar to its rationale for its opposition to a property tax reconciliation, the Staff Accounting Panel provides no substantive rationale for its opposition to this netting provision, tacitly indicating no opposition to continuing such a mechanism as part of a multi-year plan but simply opposing such a mechanism as part of a one-year rate plan. The Staff Accounting Panel simply states that the Commission should determine the disposition of such balances in the Company's next rate case. (3636).

Staff's position is unreasonable. First, as indicated above, netting is important from a financial reporting standpoint, to avoid the impact of accumulated deferrals on the Company's

[191] 2005 Rate Plan Order, App. I., p. 10.

external reporting requirements and financial statements, which Staff does not refute. Second, authorizing the netting of deferrals at the end of a one-year rate determination is no different from authorizing the netting of deferrals at the end of a multi-year rate plan until base rates are changed by the Commission, which is how the current mechanism operates.

As discussed above in the context of reconciliation of costs, the netting mechanism could also be a contributing factor to a Company decision to delay seeking rate relief. Although recent circumstances have made it impossible for the Company to avoid seeking rate relief upon the expiration of its multi-year plans, that may not be the case in the future. In fact, Staff itself tacitly acknowledges that rates established for one year only could possibly continue in the context of their proposal to establish procedures to continue the RDM beyond rate year one. (3975-3976). There would be no reason for Staff to insist that such a procedure to continue revenue decoupling is necessary if Staff was confident that the Company would be filing for new rates to take effect on or before the beginning of a second rate year (which would establish a forum for addressing a continuation of revenue decoupling).

In addition, the concern of Staff and other parties to limit the accumulation of large deferred credits and debits is evidenced by the universal support for a true-up mechanism for revenue decoupling no later than annually and more frequently if the net amount of accrued credits and debits exceed a certain level. (3971-3972; 4704-4705).

Accordingly, it would be unfortunate if the sole driver for such a filing was the need to address deferred costs that could otherwise be minimized by the netting provision that the Company proposes be continued.

The Company has made two filings with the Commission's Office of Accounting and Finance pursuant to the netting provision of its rate plan, one after the close of Rate Year 1 (the

twelve-months ended March 31, 2006) and the second after the close of Rate Year 2 (the twelve months ended March 31, 2007). The total regulatory assets and regulatory liabilities netted as a result of those filings was $406 million. (2467). The Company proposes to submit the same type of report to the Commission's Accounting and Finance Staff with respect to the continuation of the netting provision (2442), and the netting would, again, be subject to Staff's audit and prudence review.

A netting mechanism is especially appropriate given that the Company proposes to use TCC revenues above the proposed $60 million rate level imputation, along with any other available transmission revenues, to recover any total net deferrals. (2442). Using these revenues to recover net deferrals, and to mitigate any other deferrals that arise (such as from a revenue decoupling mechanism), would help to minimize the potential build up of large net deferrals that would be collected from or passed back to customers at some time in the future. (*Id.*).

VIII. THREE-YEAR RATE PLAN

The Company sponsored a three-year rate plan as an alternative to a one year case. As explained by Company witness Rasmussen, a multi-year rate plan provides the Company with greater flexibility to schedule and execute critical programs in the most cost-effective manner and places greater cost responsibility on the Company to manage its resources over several years when there may be larger swings in economic conditions and permit greater focus on operating efficiencies, as opposed to the alternative of a relatively constant focus on rate litigation. (2427).[192]

[192] Mr. Rasmussen explained that by proposing a three-year rate plan, the Company was not waiving its rights to file for new rates immediately following the conclusion of this case, if the Company views the rate change granted by the Commission for RY1 to be inadequate, or the terms of an additional rate year(s) under a multi-year rate plan to be unreasonable.

Mr. Rasmussen set forth in detail how the Company's three-year rate proposal would work. Mr. Rasmussen explained that the Company used the twelve months ending March 31, 2009 ("RY1") as a base for which projections were made for the 2nd and 3rd rate years of the plan. Mr. Rasmussen sponsored a 19-page document (Exhibit 165), which sets forth the proposed revenue requirements for RY 2 and RY 3 ($323.1 million and $334.5 million, respectively) and highlights the items for which the Company would be seeking recovery. (2469). As indicated in Exhibit 165, the Company is seeking rate increases of 3.0 percent and 3.6 percent for RY 2 and RY3, respectively.

As indicated by other Company witnesses, a multi-year rate plan provides flexibility to address other concerns raised by the parties to this proceeding. For example, the Electric Rate Panel explained that the Company could consider in the context of a multi-year rate plan mitigation measures that would result in the Company's phasing in the rate changes necessary for all classes to approximate the Company's overall system rate of return. (298-99). With respect to the issue of revenue decoupling, a multi-year plan lends itself to establishing a process for resetting targets for RY2 and RY3, rather than having to revisit the issue of revenue decoupling *de novo*. (2248).

A. <u>Position of Staff and Other Parties</u>

No party addressed the substance of the Company's three-year rate proposal. Only Staff provided a reason for its not doing so.

The Staff Accounting Panel claimed that it did not address the Company's proposal because of Mr. Rasmussen's statement that the Company is not waiving its rights to file for new rates if the Company determines that the rates set by the Commission for the first rate year are

inadequate or the terms set by the Commission for the other two rate years are unreasonable. (3551).

Staff's reason for not addressing the Company's proposal does not provide a basis for the Commission's not considering the substance of the Company's three-year rate proposal. There is no basis for requiring the Company to waive its statutory rights to file for new rates as a basis for asking the Commission to consider a multi-year rate plan. In fact, endemic to joint proposals for multi-year plans submitted to this Commission for its consideration is a standard provision whereby the signatory parties reserve to themselves the right to pursue their respective positions should the Commission fail to adopt the proposal according to its terms.[193] The Company's position in proposing a multi-year plan through the testimony of Mr. Rasmussen is completely consistent with such approach.

The only other party to address the Company's proposed three-year rate plan was Westchester, who recommends, without any supporting rationale, that the three-year rate plan be rejected because customers would be better served with a one-year rate plan. (5445).

The Commission has historically favored multi-year rate plans. No party to this proceeding has provided any evidence that the Company's proposal is unreasonable and should not therefore be considered by the Commission as an alternative to a one-year case.

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[193] See, for example, 2005 Rate Plan Order, App. I, pp. 89-90, which provides:

> Provisions Not Separable
> The Signatory Parties intend this Proposal to be a complete resolution of all the issues in Case No. 04-E-0572. It is understood that each provision of this Proposal is in consideration and support of all the other provisions, and expressly conditioned upon acceptance by the Commission. Except as set forth herein, none of the Signatory Parties is deemed to have approved, agreed to or consented to any principle, methodology or interpretation of law underlying or supposed to underlie any provision herein. If the Commission fails to adopt this Proposal according to its terms, then the Signatory Parties to the Proposal will be free to pursue their respective positions in this proceeding without prejudice.

IX. RELIABILITY AND CUSTOMER SERVICE PERFORMANCE MECHANISMS; PERFORMANCE INCENTIVES

The Company proposed that the Commission neither continue the Reliability Performance Mechanism ("RPM"), the Customer Service Performance Mechanism ("CSPI") (which includes nor the Outage Notification Incentive Mechanism ("ONIM")) that is part of the 2005 Rate Plan, nor implement any new negative rate adjustment mechanisms.

The Company's Infrastructure Investment Panel provides the following reasons why all existing penalty mechanisms not be renewed and no replacement or new mechanisms be instituted:

- no utility takes its public service obligations more seriously than Con Edison, from its senior management to its field employees;
- the idea that pre-determined economic sanctions are necessary for the Company to properly discharge its responsibilities is sorely misplaced;
- the mechanisms in effect today, while intended to provide the Company an "incentive" to perform at or above established performance standards, can, for example, result in penalties to the Company for circumstances outside of the Company's control or for unpreventable occurrences, notwithstanding efforts by the Company to perform at or above the established standard;
- superior performance by the Company, beyond the targets, has not been rewarded, but has been used to the Company's detriment by ratcheting the targets to require higher performance to avoid a penalty, thus discouraging the Company from achieving superior performance; and
- even where the mechanism provides an opportunity for the Company to argue for relief from a penalty, such opportunity is undeniably diminished as compared with an opportunity to argue against a penalty being imposed in the first instance. (1892-1893).

It bears emphasis that the Infrastructure Investment Panel does not suggest the elimination of performance standards. The recommendation is specific to elimination of the pre-established monetary penalties. (1893-1894).

The Infrastructure Investment Panel acknowledges that such standards set a performance benchmark against which the Company and its employees internally gauge their performance, and will continue to gauge their performance. In fact, it is the work ethic of the Company's employees, the recognition of the Company's duty to provide reliable service that our customers expect, and the adverse financial and public relations consequences of avoidable events, that drive the Company's performance, not the existing monetary penalties. (1893-1894).

With the Company's continued reporting to the Commission and its Staff on its ongoing performance in relation to these standards, the Commission may take appropriate action if it determines that the Company's performance in a particular area does not "measure up." However, in this context, the Commission would be more properly focused on whether a penalty is warranted in the first instance, on the basis of all of the relevant facts and circumstances, as opposed to considering reducing or waiving a penalty on the basis of circumstances that may have not been contemplated when the penalty mechanism was crafted. (1894).

The testimony presented in this proceeding provides ample evidence of the thought given by the Company to reliability and safety issues in particular. It is on this testimony that the Commission should focus its attention - investment in infrastructure and other programs aimed at improving reliability and safety – instead of monetary penalties that, in the Company's view, have no value as a deterrent to "bad behavior" and, if imposed, merely serve to unnecessarily deplete the resources available to the Company to address important system needs. It should be patently obvious, as a result of recent incidents on the Company's system, that outages and other events have potentially significant economic consequences to the Company. For example, the Company is exposed to substantial financial harm in the form of incremental expenses that are not reimbursable, claims for perishables and other damages to customer property, and exposure

to prudence inquiries, as a result of the breakdown of its facilities or processes. The Company thus has ample natural incentives to avoid outages. In these circumstances, penalties serve no legitimate public interest (that is, they do not provide the Company a greater incentive to avoid outages), but expose the Company to needless additional and substantial financial harm. Penalties of this nature only provide the Company an incentive if the Company were otherwise willing to suffer the financial consequences that naturally occur from outages, which is not the case.

The evidence in this case demonstrates the pernicious nature of the 2005 Rate Plan reliability and customer performance penalty mechanisms. As explained by former Chairman Zielinski in his testimony, such mechanisms, however well-intentioned, create what are undoubtedly unintended economic incentives. He provides, as an example, that the Company may fall slightly short of one customer service standard and incur a penalty, even if it exceeds many other standards – for which it is not rewarded – and achieves an overall performance that is well above the standards as a whole. He goes on to explain that when the Company improves performance and exceeds an individual standard, the regulatory scheme will raise the standard, making it more difficult to achieve the standard and avoid a penalty, and thus discouraging the Company from improving service beyond an existing standard. (2721-2722).

Mr. Zielinski analogizes the imposition of penalties under this system to an employee compensation system under which no increases in compensation are possible, and falling even slightly below any one performance standard results in a pay cut, even if the employee exceeds all other performance standards and his or her overall performance is exceptional. He explains that in a mobile and competitive labor market, such a scheme is self-defeating because productive employees will simply move to where rewards are offered for overall good and

improved performance. He then explains that this regulatory scheme is not effective for electric utilities even though their assets are immobile, because the capital necessary to effect service improvement and maintain good service is entirely mobile. That is, if investors are expected to support overall good or improved electric distribution service on threat of penalty, they will invest their capital where they are not threatened with penalties for good overall service, or require higher compensation for their capital that offsets penalties for overall good service. (2722).

His testimony confirms that the Company has natural internal incentives to provide good service, not the least of which are the damaging effects of adverse regulatory and public relations. Additional incentives to maintain good service include avoidance of revenue losses, unrecoverable incremental costs, customer complaints, and the cost of responding to those complaints. A regulatory scheme of performance standards and penalties that does not recognize or reward overall good performance, and raises standards in response to improved performance, thus making it more difficult to avoid penalties, adds nothing to the Company's natural incentives to provide good service, and discourages the Company from improving service. Moreover, if any regulatory performance standard, or combination of standards, were to prescribe, in effect, what action the Company should take to avoid a penalty in response to a particular operational situation, such standards would unintentionally discourage the Company from considering alternative actions that include the risk of a penalty, but that could be more effective in response to the particular operational situation. (2722-2723).

Mr. Zielinski further testified that incentive regulation would offer the Company a reward for exceeding historical levels, which would provide additional revenues to apply to improving service beyond historical levels, and that if the Company could achieve service

improvement without using all of the reward for that purpose, it could increase its returns to shareholders in the near term and achieve a long term efficiency benefit for its customers. Accordingly, penalties should not be assessed for falling somewhat below an individual performance standard when overall performance is good, but for failing to provide minimally "adequate" overall service; and they should be coupled with rewards for achieving significant improvement in overall performance. (2723).

1. <u>Staff and CPB Recommendations</u>

The Staff Infrastructure Panel recommends that the RPM established by the 2005 Rate Plan be continued with the following modifications: (1) an increase in the revenue adjustment for the overall reliability category from $48 million to $50 million, by increasing the negative rate adjustment for not meeting the duration targets from $4 million to $5 million; (2) an increase in the negative rate adjustment for one special project; (3) a new mechanism using service restoration time as a means to measure the Company's performance during storms; and (5) a new mechanism associated with the Company's Remote Monitoring System ("RMS") (4045-4055).

The Staff Consumer Services Panel and CPB's Dr. Elfner recommend certain changes to the ONIM to increase existing penalties and to Staff additional requirement for holding conference calls with public officials. (3845-3846; 4707-4710). The Staff Consumer Services Panel also recommends that the CSPI continue. (3845).

Local 1-2 recommends that the Commission implement a penalty mechanism associated with manhole maintenance to eliminate manhole congestion. (5059).

For the reasons provided by the Infrastructure Investment Panel and Mr. Zielinski and as further explained below, the Commission should reject these recommendations and, as proposed

by the Company, discontinue in their entirety the RPM, and the CSPI without instituting any new negative rate adjustment mechanisms.

The Staff recommendations generally reflect a troublesome and unwarranted trend, whereby each and every Company activity that is targeted for improvement is made subject to a performance mechanism and associated negative rate adjustment. As discussed by Company witness Hoglund, this trend will have increasingly negative financial implications for the Company, to the ultimate detriment of the Company's customers. In addition, the sizes of the negative rate adjustments proposed are disproportionate to the subject matter of the performance mechanism, and disproportionate to the aggregate financial exposure of the currently effective RPM. (1993).

When the Commission determines that the Company should improve its performance for a particular area of its business, the Company should first inform the Commission of the steps it intends to take to address the Commission's concerns. Then, the Commission, through Staff, should monitor and evaluate the Company's implementation of these steps over a reasonable period of time. If, and only if, the Commission thereafter determines that the Company has not, for good reason, properly taken action to implement its plans, should the Commission consider whether a performance mechanism and associated negative rate adjustment would be a more effective means for achieving the desired result. (1993-1994).

Separate and apart from reasons why a framework of penalties is a needlessly harmful, inefficient and inequitable approach to ratemaking, the imposition of penalties by the Commission is in excess of the Commission's statutory authority.[194] That is, as provided by

[194] In the context of "a rose by any other name…..," while the negative financial consequences that befall a utility from these performance mechanisms are today referred to as negative rate adjustments, they have been traditionally considered penalties by the Commission itself. In fact, the Commission has specifically referred to Con Edison's incentive mechanisms as penalty programs.

section 25 of the Public Service Law, a public utility may be subject to a penalty for its failure to obey and comply with a provision of the Public Service Law, or an order or regulation adopted by the Commission under the authority of the Public Service Law. And pursuant to section 24, to recover such a penalty, the Commission must commence an action in a court of competent jurisdiction in the State of New York. Under the framework set forth in the Public Service Law, any penalty sought to be imposed by the Commission is subject to a judicial process, and the Commission may not bypass that process and impose punitive economic sanctions directly on utilities.

Denoting the financial consequences of the RPM as negative rate adjustments does not provide a basis for the Commission to take action beyond the scope of its authority under the Public Service Law. While the development of a three-year rate plan may provide a forum in which the Company may agree to continue and/or modify existing performance mechanisms, there is no basis for continuing any such mechanisms in the context of this litigated proceeding.

For the foregoing reasons and the reasons set forth below, the Commission should reject the new performance mechanisms proposed by Staff and not continue the existing performance mechanisms, either in the current form or with the modifications proposed by Staff and CPB, or establish any new mechanisms.

> For [Con Edison's] Electric Service Reliability Performance Mechanism, network-only targets (both rewards and penalties) will continue to be suspended through 2002, but radial targets, including combined Westchester radial/network targets (both rewards and penalties) will be reinstated as of December 1, 2001. Finally, the major outage <u>penalty mechanism</u> will be reinstated as of December 1, 2001, except that this mechanism will continue to be suspended through 2002 for the lower Manhattan area. … Many of the provisions that had been temporarily suspended incorporate annual calculations for the determination of <u>penalties</u> and incentives. As a result of the elimination of several months from the incentive and <u>penalty</u> programs, those calculations can no longer be performed in their normal manner. Case No. 01-M-1263, Emergency Restoration of Utility Service, Order issued November 26, 2001, 2001 WL 1763242 [emphasis added].

If notwithstanding the Company's position that there be no penalties, the Commission determines that performance penalties are appropriate and necessary, it still cannot reasonably continue and expand the existing penalty regime on the basis of the record in this case.[195] A separate phase of this proceeding, which Con Edison would not oppose, would have to be established to develop a symmetrical structure of financial incentives and disincentives based on the evidence in this record. The evidence also shows that the components of an RPM cannot reasonably be considered permanent fixtures. That is, once it is reasonably determined that a performance mechanism has served its purpose (*i.e.*, the Company has demonstrated a change in approach, which has become part of its normal processes, and achieved the desired goals for a reasonable period), it would be arbitrary and capricious to retain that mechanism in the RPM or the CSPI.

Staff proposes that the restoration mechanism become effective January 1, 2008 and the RMS mechanism become effective January 31, 2008 (Exh. 272, p. 1, 22) However, the earliest that the RPM could become effective is April 1, 2008. Con Edison is currently operating under the terms of the RPM approved by the Commission in the 2005 Rate Plan Order. As stated in the 2005 Rate Plan, the Company's current RPM remains in effect "through the end of the Electric Rate Plan and thereafter until electric base delivery rates are reset by the Commission." (2005 Rate Plan Order, App. I, p. 36). The 2005 Rate Plan ends on March 31, 2008. (*Id.* p 3). Moreover, performance mechanisms designed to achieve certain targets must, in any event, be forward-looking and not applied retroactively.

[195] The nature of any performance targets and the associated penalties must also be considered in the context on any adjustments that the Commission may make to the Company's capital and O&M spending programs. To the extent the Commission determines that certain projects should not be undertaken or should be curtailed or deferred, or makes a lump-sum slippage adjustment, performance targets and associated penalties must be adjusted to reflect the impact of the adjustments.

Further, to the extent that the Commission approves the new RMS performance mechanism, the Company has asked the Commission for the resources needed to provide a reasonable opportunity to meet the established targets and thereby avoid the associated penalties. (2030-2031). The Commission will not likely issue its order addressing these proposals until March 2008. Consequently, Staff's proposal to commence the RPM on January 1, 2008, must be rejected.

2. Reliability Category

In the Reliability Category of the RPM, the Staff Incentive Panel proposes Threshold Standards and a Major Outage Mechanism.

a) Threshold Standards – Staff's Proposal

Staff proposes to establish penalties associated with targets for measuring the reliability of the Company's electric system. The targets would measure the frequency of service interruptions to customers using the System Average Interruption Frequency Index ("SAIFI") and the duration of outages using the Customer Average Interruption Duration Index ("CAIDI"). The threshold standards consist of two SAIFI targets and two CAIDI targets. One SAIFI target (0.015) is applicable to system-wide performance on the Company's network distribution system. The other SAIFI target (0.500) is applicable to system-wide performance on the Company's non-network distribution system, also referred to as the "radial system." One CAIDI target (3.35 hours) is applicable to system-wide performance on the Company's network distribution system. The other CAIDI target (1.75 hours) is applicable to system-wide performance on the Company's non-network distribution system. (4048-4049, Exh. pp. 6-7).

The SAIFI and CAIDI targets are based on a methodology stated in Appendix E to a Con Edison rate plan contained in a settlement agreement approved by the Commission in Case 00-M-0095 in Opinion No. 00-14. Appendix E to that Settlement Agreement states (Exh. 279, p. 5):

> In Cases 90-E-1119, 95-E-0165, and 96-E-0979, the Commission adopted standards establishing minimum performance levels for both frequency and duration of service interruptions for the network and radial systems in the six operating areas of Con Edison's service territory. Under these standards, the frequency of service interruptions is measured under the System Average Interruption Frequency Index (SAIFI), and the duration of service interruptions is measured under the Customer Average Interruption Duration Index (CAIDI). The minimum performance levels established in those cases are set forth as certain minimum SAIFI and CAIDI values. The Area Performance Targets for Con Edison's reliability established in this reliability mechanism are those minimum performance levels as modified herein.

Staff's proposed SAIFI and CAIDI targets are the targets used in the RPM incorporated into 2005 Rate Plan. In support of using the proposed target levels, Staff states (4049):

> A review of Con Edison's performance shows under normal operation the Company has performed better than the targets set, and in cases where the Company is experiencing a serious problem, such as the Long Island City outage, the Company can not meet these thresholds. These targets are indicative of long-term trends, which is our primary focus.

Staff proposes annual penalty amounts of $5 million for each of the four targets with a total amount of $20 million at risk per year under the Threshold Standards. Staff notes that it is proposing a $1 million increase in the two CAIDI penalty amounts in comparison to the $4 million penalty amount applicable for each provided in the 2005 Rate Plan. Staff's reason for the increase is "to ensure both frequency and duration has the same financial impact." (4050).

b) <u>Threshold Standards – Con Edison's Presentation</u>

For the reasons discussed previously in this Brief, the Company proposes that the Commission not approve an RPM for the Company and instead approve the incentive regulatory framework recommended by Company witness Zielinski. In the event that the Commission

adopts an RPM containing threshold standards to measure the Company's reliability performance, Company witness Lewis recommended a reliability threshold performance mechanism that differs from that proposed by Staff in five important ways summarized as follows (1604-1605):

- First, any proposed standard that includes SAIFI or CAIDI must take into consideration the Company's recent implementation of a new Outage Management System ("OMS") called System Trouble Analysis and Response ("STAR") across its system.

- Second, the distinct threshold standards for the Company's network and radial systems should be combined into a standard for the entire system, effectively reducing the Panel's proposed four standards into two, one for SAIFI and one for CAIDI.

- Third, the threshold standards should be based on the Company's most recent historical performance, excluding anomalies.

- Fourth, the threshold performance standards should take into consideration the natural variability of reliability results caused by weather and other random events.

- Fifth, penalties should be eliminated from the threshold standards and replaced by an annual corrective action plan that will describe in detail the actions the Company should take to address any performance result that does not meet the minimum standards.

(i) <u>Impact of Outage Management Implementation</u>

STAR is an automated OMS that, among other functions, calculates the incidence and duration of customer outages. During the 2007 calendar year, Con Edison achieved effective implementation of its STAR system in all its operating areas and updated its policies and procedures for recording outages accordingly, resulting in a transition away from a semi-automated data collection process for identifying, responding to, and maintaining a historical record of outages.[196] STAR replaced the legacy outage management system, called the

196 Con Edison's Westchester operating area has had the STAR OMS in place since before 2001. (Exh. 116, p. 10)

Emergency Control System ("ECS"), that used manual methods to calculate the incidence and duration of customer outages. (1605-1606; Exh. 116, p. 10).

The legacy EMS systems for the Company's networks were not able to link customers to specific points of service. The new OMS and related customer mapping systems for the network provide direct linkage. (1610). The new OMS and associated customer mapping systems enable the Company to accurately associate customer outage calls with specific electric facilities during an outage. Particularly on the network system, the new STAR OMS provides improved customer outage counts and more accurate outage durations as the Company can more effectively identify and confirm outages on the network system and the customers impacted. On the less complex radial system, improved customer connectivity and outage modeling also result in improved customer outage counts and more accurate outage durations.[197] (1612-1613).

Company witness Lewis testified that based on his review of outage tracking systems used by utilities transitioning from existing legacy outage management systems to new generation systems, in the vast majority of cases, the implementation of a new OMS such as STAR, produces substantial negative variances in reported levels of reliability indices such as SAIFI and CAIDI, independent of the actual reliability experienced by customers, which remained unchanged. (1606; 1613-1614). By negative variations, Mr. Lewis meant that "[p]ost-

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197 The report on Mr. Lewis' study describes the improvement in outage tracking resulting from Con Edison's OMS as follows: (Exh. 116, p. 12)

> Con Edison's legacy process; particularly on the network system was unable to automatically match customers to service points to generate customer counts for each outage. The process was manual and system operators had to provide estimated customer counts based on limited information. This was particularly difficult for smaller outage on the complex network system. By contrast, in a state-of-the-art OMS all of the outage calls are captured electronically from the CIS and the system is capable of sorting, prioritizing and associating thousands of outage calls simultaneously. The software has an electronic map of the distribution system with every customer electronically mapped to a service point. As a result, the OMS can quickly match every customer call with a specific transformer or service point and predict the number of customers affected. The system also immediately sorts and identifies the first customer call to ensure an accurate outage start time.

OMS reliability statistics indicat[e] more frequent outages, longer durations, or more customers impacted [that] are simply caused by using a different set of systems and processes for capturing, analyzing, and reporting data." (1607).

Mr. Lewis stated that the effect of the transition from a legacy system to a new automated OMS is analogous to measuring the distance of a trip in miles and then changing the measured distance to kilometers. The distance remains the same, but the measurement system has changed substantially. (1606).

Con Edison's system is extremely reliable. Mr. Lewis points out that no other large investor utility in the United States provides better reliability on a system-wide basis. (1603). Con Edison's annual system-wide interruption frequency is about 133 interruptions per 1,000 customers compared to the industry average of 1,200 per 1,000 customers.[198] (*Id.*) The high reliability remains unaffected by the use of STAR OMS, but the use of STAR metrics will yield outage data that will differ from those produced by the EMS. The impact is not on "reliability" but on "reliability statistics." (1606).

While the magnitude of the impact on reliability statistics is generally correlated with the level of automation inherent in the legacy outage reporting system, a detailed study is necessary to provide a reasonable estimate of the impact. (1606; 1613-1614). Mr. Lewis and his firm PA Consulting conducted a comprehensive study ("the PA study" or "the study") to determine the impact on reliability statistics caused by Con Edison's implementation of the STAR OMS and associated changes in data collection systems, policies, and procedures. (1609).

Mr. Lewis also stated that it was not uncommon for utilities implementing a new OMS to experience a significant negative impact on reliability indices such as SAIFI and CAIDI and that

[198] As indicated by Staff's proposed 15 per 1,000 network SAIFI target applicable to the Company's underground network areas, the interruption rate for network customers is substantially lower.

multiple jurisdictions across the United States with electric reliability standard shave addressed the issue. (1608).

The Commission has recognized the potential impact of OMS implementation on a utility's ability to satisfy SAIFI and CAIDI standards. In Case 00-E-1273, Central Hudson Electric Rates, "Order Staying Reliability Targets and Rate Adjustments," September 29, 2003, the Commission stated:

> Under the Order Establishing Rates, however, the reliability targets were subject to reevaluation upon Central Hudson's installation of a new Outage Management System (OMS) for the collection and reporting of the outage data upon which the SAIFI and CAIDI indices are based. Reevaluation was deemed warranted if improvements in data collection following installation of OMS indicated a deterioration in reliability performance attributable to better data collection and analysis rather than to declining performance.

The PA study analyzed the difference in reported reliability indices between Con Edison's legacy reporting systems and processes and its new OMS in order to estimate the expected change to SAIFI and CAIDI resulting from a transition from the legacy systems to the new OMS. (Exh. 116, pp. 4, 10). The PA study was designed to determine the differential between Con Edison's legacy method and its STAR OMS in determining the number of customers interrupted for a given outage. (Exh. 116 p. 14). The study results were used to make adjustments to historical outage results produced by the legacy method in order to reflect Con Edison's current OMS environment and arrive at more accurate reliability metrics for the purposes of SAIFI and CAIDI reporting to the Commission by adjusting the current threshold standards for SAIFI and CAIDI that are based on Con Edison's historical legacy reporting. (Exh. 116, p. 11).

Study Methodology

Mr. Lewis summarized the methodology of the PA study in his testimony (1609-1610), and provided a detailed explanation of the study methodology in the report on his study. (Exh. 116).

The PA study used a stratified random sampling approach to estimate the customer count differential between the legacy method and STAR. The study randomly sampled more than 1,500 outage results from all outage events (excluding major storm related events) reported to the Commission for the 2005 calendar year, treating each operating area as an individual population and sampling from those populations.[199] The PA study covered Con Edison's Bronx, Brooklyn, Manhattan, Queens, and Staten Island operating areas. The outages for the entire year, initially divided into subpopulations by operating area, and then each subpopulation was stratified into customer groups and outages, were randomly selected from these strata using a random number generator. Included in the selected sample were both "large" and "small" outages and all types of weather conditions (excluding major storm) (Exh. 116, p. 14).

The study used the STAR system simulation mode to "replay" each 2005 outage in the random sample as if it had occurred using the new OMS. The study included a detailed analysis of the ECS records associated with each outage in the sample and used the detailed connectivity and customer count databases in the new OMS to conduct a comparison of the two systems. (Exh. 116, pp. 14-16). The results of the simulation and analyses were intended to provide a direct comparison of the actual data reported to the PSC and the data as it would have been reported had the new OMS been in use in 2005. (1609).

[199] Westchester was excluded from the final results as that operating area had the OMS in place throughout the study period of 2001 to 2005. (Exh. 116, p. 10). The 2005 data year was used because it contained no large reliability data anomalies and the results were produced by the legacy system.

Once the customer count differential was determined for each outage event in the sample, adjustment factors were calculated by outage size, operating area, and network or radial design. In order to accurately apply the adjustment factors to the entire population of 2001 to 2005 historical outage data, that population of outage data was first stratified identically to the sample – by the number of customers interrupted per outage – and then the adjustment factors for the respective strata were calculated. This approach captured the changes in the mix of outage sizes (as measured by the number of customers interrupted) from year to year. Each outage in the entire population of outages between 2001 and 2005 was examined and adjusted based on this methodology. The study developed separate network and radial adjustment factors by operating areas to capture the significant differences between these two systems. In effect, the aggregate number of customers interrupted for each operating area in each year (2001 to 2005) was adjusted by the operating area's sample customer count adjustment factor. (1614-1615; Exh. 116, p. 16).

Once the historical data from 2001 to 2005 was adjusted, a five-year average of outage data was calculated. SAIFI and CAIDI were then calculated on the adjusted historical data for comparison with pre-adjustment figures. The five-year average SAIFI and CAIDI of the adjusted data set was compared directly to the five-year average of the legacy data to determine an overall impact over the entire study period. The resulting differential constituted the impact of OMS implementation on Con Edison's reliability metrics. (1611; Exh. 116, p. 16).

Study results

The study found a statistically significant impact on SAIFI and CAIDI on a system-wide, network, and radial basis as a result of Con Edison's transition from legacy processes and systems to the new STAR OMS. With OMS reporting, outages across the sample resulted in

higher outage counts and longer duration than reported under the legacy system. Outages with fewer customers experienced a greater change between the results of the legacy and the new OMS. Network outages were impacted to a greater extent than radial outages. The percentage increase in outage counts (SAIFI) and in longer duration (CAIDI) were as follows:[200] (1610-1612).

OPERATING AREA	SAIFI	CAIDI
System-wide	17%	24%
Network	175%	25%
Radial	4%	0%

(ii) <u>Modification to Threshold Standards</u>

The SAIFI and CAIDI threshold standards proposed by Staff are based on the methodology used for the RPM in the Case No. 00-M-0095 settlement agreement. (4048). As noted earlier, the threshold standards in that RPM were the minimum performance levels for both frequency (SAIFI) and duration (CAIDI) of service interruptions that the Commission adopted in Cases No. 90-E-1119, 95-E-0165, and 96-E-0979. (Exh. 279, p. 5).

[200] The radial system contributed approximately 93 percent of customer minutes of interruption for the Con Edison system in 2005. Thus, the system-wide impact is driven in large part by sample results for the radial system. Accordingly, the relatively smaller radial adjustment factors are more heavily weighted when combined with the larger network adjustment factors and rolled-up to the system level. (1612).

The SAIFI and CAIDI minimum performance levels adopted by the Commission in Cases No. 90-E-1119, 95-E-0165, and 96-E-0979 were based on five years of historical data from 1985 to 1989. In Case No. 95-E-0165, Proceeding Regarding Proposed Changes to the Standards on Reliability of Electric Service Filed in Case 90-E-1119, Order Instituting Proceeding and Soliciting Comments, May 10, 1995, the Commission sought comments on Staff's February 2, 1995 memorandum stating:

> Staff's original determination of the 184 standards [applicable in the various electric utility operating areas throughout the state] was based on five years of historical data (1985-1989) … Staff's initial method for setting the SAIFI and CAIDI values at Minimum and objective Levels was to take the average of the best three out of five years to establish the Objective Level and the average of the worst three out of five years of the historical SAIFI and CAIDI indices to establish the Minimum Level. Staff adjusted the numbers after consideration of factors such as trends among indices, the average, high, and low values of multi-year indices, demographic, geographic, and load characteristics of an operating area, and the relative performance of an operating area in relation to other operating areas within a given utility's franchise area.

In this proceeding, Staff has proposed RPM performance thresholds: 1) developed from Con Edison's 1985 to 1989 SAIFI and CAIDI performance, 2) reflecting performance measured by the Company's legacy EMS outage tracking system, and 3) derived from a simple average of annual results. (1616-1617). Each of these three points raises an important concern that Mr. Lewis discusses.

The first concern is the use of a 20-year old data set to establish a current reliability standard threshold for the RPM. As Mr. Lewis explained on cross examination, advances in utility industry technology, such as advances made in switches, computerized monitoring, and feeder processing changes, that can improve reliability performance are not captured in standards that reflect 1980s technology and practices. (1662-1663).

The second concern is the mismatch between measuring the Company's current reliability performance on the basis of threshold standards derived from the less accurate EMS legacy system while reporting the Company's current reliability performance using the more accurate STAR OMS. Mr. Lewis states the problem as follows "It is inappropriate to set a reliability standard based on historical reporting from one system, but evaluate performance against that standard based on reporting from a completely different measuring system such as the new outage management system (OMS)." (1606).

The third concern is that reliability standards based on a simple average do not account for "the natural variability of results," *i.e.*, normal annual performance fluctuations "driven primarily by weather and other events beyond the control of the utility." (1616). Mr. Lewis stated the problem as follows: (1616-1617).

> If a performance threshold is set at the historical average level of performance, the Company would have to improve its underlying reliability to avoid exceeding that threshold due to the normal fluctuations expected to occur in the future. Therefore, the Company would actually have to improve, perhaps substantially, its average performance so that all future fluctuations remain below the threshold established based on a simple average.

Thus, a penalty-enforced RPM threshold standard based on the historical average level of performance "is setting any utility up for failure." (1669).

To address these concerns, Mr. Lewis recommends that the threshold standards be based on a two standard deviation deadband above and below the average of Company's five years of historic SAIFI and CAIDI results from 2001-2005, excluding major storms and other outages that are beyond the Company's control and adjusted to accommodate the impact of OMS implementation on Con Edison's SAIFI and CAIDI. (1617-1621; 1624-1625).

The use of the Company's recent five year SAIFI and CAIDI performance updates the 20-year old threshold standards to address advances in utility industry that can improve reliability performance.[201]

The adjustment of the 2001 to 2005 performance data addresses the fact that these data reflect the Company's use of the legacy EMS to identify customer outages and the threshold standards would not otherwise be consistent with the STAR OMS that the Company will use to identify customer outages under the RPM.[202]

The application of a two standard deviation deadband above and below the average of Company's OMS adjusted 2001-2005 performance accommodates the natural variability of results that follows from establishing a performance standard based on a simple average, *i.e.*, the average of the Company's 2001 to 2005 performance. Mr. Lewis stated that applying two standard deviations as a natural variability range provides a 95 percent probability that the true average falls within the stated range and reasonably reduces the likelihood of non-compliance purely as a result of expected natural statistical variation in a distribution system performance. Mr. Lewis stated, "[E]xceeding the standard under two standard deviations suggests the cause is likely other than natural variability of results."(1619). The 95 percent probability range will expose any actual performance deterioration over time because deteriorating performance would produce observations outside of the 95 percent band of normal statistical variation. (1618-1621).

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[201] Mr. Lewis recommended excluding 2006 data because the impact of the Long Island City event on reliability statistics would substantially increase the five-year average. As a result, the threshold standard for Con Edison would not be appropriate because "the thresholds would have been much, much higher." (1618; 1665).

202 As described by Mr. Lewis, the adjustment to historic 2001-2005 data would reflect the methodology of the PA study

> by applying the adjustment factors (as determined by the study) for each sample stratum within each operating area to the identical operating area stratum for the entire population of outages between 2001 and 2005. The adjusted five-year historical outage data will then be used to calculate adjusted SAIFI and CAIDI for each of the five years in the sample period (2001-2005). (1625).

Mr. Lewis' recommendation for using a deadband based on two standard deviations is supported by his study (Exh. 117) of reliability benchmarking data and five consecutive years of historical reliability data for 20 utilities to determine how often each company would have violated a threshold established at one and two standard deviations above the historical average. He found that not one of the twenty utilities would be able to fully comply with a threshold established at one standard deviation above the average. With the threshold set at 2 standard deviations above the mean, the performance of all the utilities was within the hypothetical standard with 60 percent to 70 percent of utilities performing within 10 percent of exceeding the standard. (Exh. 117).

Mr. Lewis concluded that "2 standard deviations above the average is the most appropriate multiple to use to enact a policy of maintaining reliability performance. This approach appropriately reduces the likelihood of non-compliance purely as a result of expected natural statistical variation in distribution system performance." (1620). During cross examination, Mr. Lewis testified that "the two standard deviation issue will maintain current levels of reliability." (1675). Mr. Lewis also stated during cross that at 1.75 deviations utilities would exceed their performance thresholds while the assumption is that reliability is relatively constant at those utilities. (1677).

In addition to the above three adjustments to the threshold standards (use of 2001-2005 data, adjustment for OMS, and two standard deviation deadband), Mr. Lewis also recommends that Con Edison's reliability performance should be based on overall system-wide SAIFI and CAIDI, inclusive of both network and radial systems. The network system represents less than 7 percent of the total customer minutes of interruption on the total Con Edison system and assessing network performance separately invites sub-optimal allocation of resources that could

hinder Con Edison's ability to achieve its goal of maximizing overall system reliability for all customers. (1626).

Mr. Lewis' recommended performance thresholds are: System-wide SAIFI – 201 and System-wide CAIDI – 3.94 hours. (1628). The combination of OMS adjusted historic data and a 2 standard deviation structure would enable the Commission to establish system wide reliability thresholds that accommodate both OMS implementation and natural variability of results. This structure will promote the maintenance of reliable service to customers and will provide a reasonable chance for the Company to achieve the threshold. (1626-1627).

(iii) <u>Incentive Structure</u>

Staff proposes that the threshold standards include financial disincentives for failing to meet the target performance levels for network and radial SAIFI and CAIDI totaling $20 million annually. Based on his experience, Mr. Lewis has found that "financial disincentives of this magnitude are not necessary to motivate a utility to achieve reliability standards." (1624). Mr. Lewis observed that senior management at utilities is very focused on reliability and other service quality measures and take pride in the service they perform. He acknowledges that the reporting and tracking of reliability statistics required by regulatory commissions has helped focus the industry on the importance of service reliability. But large penalties do not provide additional incentives for a utility to deliver reliable service to its customers and therefore are punitive and unnecessary. (1624).

Mr. Lewis recommends that penalties be eliminated from the threshold standards and replaced by a corrective action plan submitted to the Commission that would describe in detail

the actions the Company will take to address any performance result that does not meet the threshold level. (1605; 1625).

If the Commission determines that reliability performance penalties are appropriate and necessary, the evidence of record in this case would only support a symmetrical structure of financial incentives and disincentives (1997), such as that proposed by Mr. Lewis which provides penalty and reward thresholds around a two standard deviation deadband. (1625-1626).

c) Major Outage Mechanism

The Staff Infrastructure Panel's mentions that its proposed RPM includes a "major outage mechanism." (4049). Their testimony contains no further references to this mechanism other than Exhibit 275, pp. 8-9, that mentions the terms of the major outage mechanism. The Commission must reject the major outage mechanism because there is no substantial evidence to support it in the record of this proceeding.

3. Special Projects

The panel proposes five measures in the "Special Projects" category of the RPM. These are measures for the completion of work associated with double poles, shunts, street light, and over duty circuit breakers, plus a performance target for the Company's remote monitoring system. (4052; Exh. 275, pp. 10-23).

a) Remote Monitoring System

Under the special project category, the Staff panel proposes a Remote Monitoring System ("RMS") performance mechanism that would penalize Con Edison if 95 percent of the RMS units in each network distribution system are not reporting beginning January 31, 2008.[203]

[203] The RMS consists of three main components: the transmitter, receiver, and feeder pickup coil. The transmitters are installed at the network transformer to monitor and transmit data from the transformer and its associated network protector. Most transformers and their transmitters are located in below-sidewalk underground vaults that are exposed to the external environment. The transformer and network protector switch information are transmitted

(4053-4054; Exh 275, pp. 21-22). The RMS mechanism has two requirements and two associated monetary penalty components. First, the Company would have to achieve 95 percent RMS unit reporting in each network by January 31, 2008, and would incur a $5 million penalty for each network that does not achieve the 95 percent unit reporting target by January 31, 2008. Second, any time after January 31, 2008 that the reporting rate for a network falls below 95 percent, the Company will incur a $10 million penalty. (Exh. 275, p 22).

Staff's proposal does not state when and how each network should be measured regarding 95 percent RMS unit reporting. In Exhibit 276, Staff's data response acknowledges that it does not propose when and how each network should be measured and states that Staff "looks to the Company to recommend the best practice to ensure the networks remain at a 95% reporting rate throughout the year." (Exh. 276).

For the reasons more fully discussed below, the Commission should not adopt the RMS mechanism. An incentive mechanism is not needed to encourage Con Edison to maintain RMS availability. Con Edison is committed to maintaining the best RMS reporting rates consistent with the available technology, reasonable cost, and system operation requirements and is already close to achieving a reporting rate that meets this goal. The Company has set and has nearly achieved an ambitious RMS reporting goal to achieve and maintain 95 percent RMS availability

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from the transmitter to the RMS receiver installed in the network's supply substation via Power Line Carrier communications technology utilizing the transformer's high-voltage distribution feeder. The data signal is "detected" by the third key component, the "pick up coil" located on the electric cable in the substation. The receiver retrieves the signal and processes it for dispatch to the Company's computer systems. The data received is utilized by information applications available to Company engineers and operating personnel. Since the system has evolved over a period of two decades and continues to operate, it remains a mixture of various technologies and components.

The Company has a total of 23,615 transmitters on its system. Forty-two percent of these are first generation transmitters, which were installed beginning in 1982 when the RMS program was first implemented and are about 20 years average age. The second generation units currently in service comprise 38 percent of the total population. These are approximately ten years average age and were installed beginning in 1995. The third and current generation of RMS unit began service in 2006 and is targeted to replace the first generation and any failed units. These units are currently the most advanced in terms of capabilities and reliability. Currently, approximately 20 percent of the system has the 3rd generation transmitters. (2016).

on a regional basis with no network at less than 90 percent availability. Significant uncertainties make unrealistic an expectation of continuous 95 percent availability in all 60 networks. These uncertainties include high equipment-failure rates, system conditions and manpower allocation priorities that impede equipment repairs/replacement, and the inherent limitations of the RMS communication technology. In addition, Staff's $10 million penalty per network without limitation is extraordinarily excessive and counterproductive for the safe and reliable operation of the electric system.

(i) Con Edison's RMS Improvements Render the RMS Mechanism Unnecessary

The proposed RMS mechanism is entirely unnecessary and unwarranted. Over the past several years, Con Edison has upgraded the RMS technology and improved its maintenance processes to address a variety of problems with the RMS legacy technologies that have historically reduced unit reporting rates.[204] (2015-2022). This work has steadily enhanced the

[204] Con Edison's Infrastructure Investment Panel testified at length about Con Edison's efforts to improve the remote monitoring system. (2017-2022). These efforts demonstrate the Company's ongoing commitment to maintaining the best RMS reporting rates consistent with the available technology, reasonable cost, and system operation requirements. The IIP discusses the Company's:

- work to develop and deploy what is now by far the largest RMS system in the world;
- efforts to enhance the RMS technology and overcome the reluctance of the manufacturers holding the equipment patents;
- ultimately unsuccessful efforts over several years to develop an alternate technology and monitoring system;
- work with other manufacturers beginning in 2004, once the patents expired, to promote RMS technology advances. These efforts produced a new receiver, now installed in all area substations, with increased signal and frequency sensitivity, self-diagnosis tools including automated pick-up coil testing, and improved data correction. These efforts also produced the new third generation transmitter with higher output capability and improved protection from the environment; and
- Ongoing work with manufacturers to develop and deploy improved RMS technology. (2017-2021).

system to the point that in April 2007, each region first achieved an average availability of 95 percent for the networks in the region. (2024).

The Company's goal for RMS reporting is to maintain 95 percent RMS availability on a regional basis reflecting the average unit reporting rate of each network in the region with no network at less than 90 percent availability. While the Company first achieved this goal in all three regions in April 2007, progress has not been uniform across the regions. In August 2007, the Manhattan and Bronx-Westchester regions achieved that goal, but the Brooklyn-Queens Region fell just short with the average reporting rate of its 18 networks at 94.5 percent and 16 of the 18 networks at or above 90 percent reporting (11 above 95 percent). (2024-2025). In August 2007, 42 of the 60 networks in all regions reported at 95 percent or higher, 16 reported between 90 and 95 percent, and two networks reported at 89.5 and 87.8 percent, respectively. (2024-2025).

An incentive mechanism is not needed to encourage Con Edison to maintain RMS availability. The Company's extensive, costly, and successful efforts since 2004 to modernize the legacy RMS system and its progress in achieving an ambitious goal of 95 percent regional RMS availability demonstrate the Company's commitment to achieve and maintain a 95 percent regional RMS availability. (2028).

The Company will continue its program to upgrade the system with the third generation transmitter, investigate networks with less than 95 percent reporting to determine the cause, and continue to develop solutions for improvement in technology. The Company has already invested $5.1 million to upgrade all 62 receivers in the area substations and is proposing in this proceeding a $125 million, 10-year "Transformer Remote Monitoring System " program to upgrade the over 21,000 first and second generation transmitters on the system to the current

third generation technology needed to support improved unit reporting. (1916-1917; 2020-2021; Exh 133, p. 2).

(ii) <u>Staff's Proposal for 95 Percent Network Reporting Is Unreasonable</u>

Staff's proposed incentive target – 95 percent RMS availability in every one of the Company's 60 networks – is unreasonably aggressive. Con Edison will strive to achieve and maintain its RMS reporting goal of 95 percent RMS availability across each region, but maintaining this reporting level at all times even at the required level is aggressive and uncertain. As mentioned above, the Company first achieved 95 percent reporting in each region in April 2007 (2023), but in August 2007, the Brooklyn-Queens Region reporting rate slipped below 95 percent to 94.5 percent. (2025). Significant uncertainties make unrealistic an expectation of continuous 95 percent availability in all 60 networks.

One important consideration is that about 21,500 first and second generation RMS transmitters remain in the field, some since the 1980s, and will not be completely replaced for ten years. These units are installed in the open environment of transformer vaults and are subject to premature failure due to exposure to the elements. The current failure rate of these transmitters is 6 percent per year. It will cost $125 million to upgrade 21,500 transmitters to third generation units. (2026). Third generation units will improve reporting rates because they are installed inside the protected environment of the network protector housing and are less prone to water damage and because they have a higher signal output capability. (2021). The Company proposed to install the currently available technology (third generation transmitters) to improve reporting rates and monitoring capabilities. Because of the cost of this program, as well as the need for resources with appropriate electrical training and technician level experience (not

currently available from contractors), the program is planned to be completed over the next 10 years. (2017; 2026).

Hazeltine Corporation, the original manufacturer, claimed the mean time between failures ("MTBF") was 60 years for the first generation transmitter and 62.5 years for the second generation units and that an overall 95 percent system availability could be expected at this optimal performance level. However, actual experience has demonstrated that this was highly overstated, and in reality the actual MTBF for the first and second generation transmitters is less than 17 years. (2022-2023). Staff's proposal for 95 percent unit reporting replicates Hazeltine's projection but remains unreasonable until Con Edison can install third generation transmitters with better MTBF than the earlier generation units.

Another important consideration is system requirements that could affect RMS availability. Repairs and upgrades are dependent on the availability of construction forces. In any given time, priority system requirements may compete for the availability of field forces and interfere with the repairs needed to maintain 95 percent availability in a network. RMS pick-up coils on the individual feeders at the substations fail at a 3 percent annual rate and interfere with RMS reporting. A feeder outage is required to replace a defective coil entailing manpower from both Electric and Substation Operations. System conditions may delay taking a feeder out of service to repair a defective coil, and this delay can affect RMS availability. (2026-2027).

Another important reason for less than optimal RMS reporting is the Power Line Carrier ("PLC") technology used to transmit data from the field to the substation. PLC technology, which was developed prior to the advent of fiber optics and cellular technologies, can transmit high volume data, but the "noise" on the signal transmitting the data – from sources such as the

subway traction system, large motors (*e.g.*, elevators), and the Company's own substations – detracts from satisfactory performance.

(iii) <u>Staff's $10 Million Penalty Amount Without Limitations Is Extraordinarily Excessive and Counterproductive</u>

Con Edison has an RMS system in 60 underground second contingency design networks. (2024). Consequently, the proposed RMS mechanism creates an extraordinarily large potential exposure for the Company through the unlimited application of $10 million per network penalties.

The $5 million penalty assessment for networks that do not achieve 95 percent unit reporting by January 31, 2008 could be imposed once per network. It would appear that the ongoing failure to achieve 95 percent reporting in a network that did not achieve 95 percent reporting on January 31, 2008 would result in a $10 million penalty at each subsequent periodic measurement juncture. Thus, the Company could potentially be penalized $600 million should each of the 60 networks not achieve 95 percent reporting at a periodic measurement juncture. Assumedly, if the same 60 networks did not meet the 95 percent rate at a second periodic measurement juncture, another $600 million penalty could attach. No justification exists for such an extraordinary and counterproductive penalty.

The specter of such severe penalties could encourage the Company to divert resources from other functions that are necessary to maintain safe and adequate service to customers. (2029).

The unlimited $10 million per network penalty amount is obviously radically disproportionate to $3 million annual penalty amounts proposed for the other proposed "special project" performance mechanisms that Staff believes should be adequate to motivate the Company's conduct. Staff has made no showing why such extraordinary penalties, with the

potential for unlimited liability, are warranted for the RMS mechanism. For example, the Company would have been penalized $180 million just for its August 2007 performance (18 networks less than 95 percent) if the mechanism were in effect then.

The proposed $10 million per network penalty when any of the 60 networks RMS reports at less than 95 percent is, for example, grossly disproportionate to the $10 million network outage penalty proposed in the major outage mechanism. (Exh 275, pp. 8-9). RMS reporting at less than 95% does not interrupt service to any customers, much less to an entire network; yet, from a financial liability standpoint, Staff proposes the same dollar penalty for a failure to achieve a reporting level with no consequences to customers as it proposes for a network outage that has actual consequences for customers. Further, while Staff proposes that the major outage penalty be limited to three major outages in a year, Staff proposes unlimited $10 million penalties for networks with RMS reporting below 95 percent and unlimited $5 million penalties for networks not reporting by January 31, 2008.

Staff's proposed unlimited RMS penalties are grossly out of proportion to the other penalties proposed in the RMS. If the Commission were to adopt the RMS mechanism, a materially lower individual penalty level and an overall penalty limitation is warranted.

(iv) Additional Resources Required to Maintain 95 Percent RMS Reporting by Network

In addition, should the RMS penalty mechanism be adopted, the Company would require additional resources to meet RMS network availability levels that the Company had not contemplated in establishing the revenue requirement for its rate filing. The Company would focus on a reporting rate improvement strategy that would include intensified monitoring, testing and repair of the RMS transmitters, receivers, pickup coils and information systems. Based on the projected failure rates and the cost of additional component replacement, the incremental

increase in total annual equipment costs (*i.e.* RMS component replacements required to support a 95 percent reporting rate in each network) is estimated to be $5 million. In addition, an organization, comprised of a section manager, planners, and supervisors, plus 48 specified field workers, is required to provide testing, installing and monitoring. The labor cost of this organization approximates $10 million (based on 48 employees at a $100 man-hour rate). However, the additional staffing may have to be supplemented by contractor forces that, and assuming such resources were even available, would require significant training before being capable of performing this work. Therefore, the total cost to maintain RMS reporting at 95 percent in each network is estimated at incremental increase of $15 million annually to the existing program. (2030-2031).

b) <u>The Current "Special Projects" Should Transition To Standard-Only Measures Without Penalties</u>

As stated by the Company's Infrastructure Investment Panel, the measures for double poles, shunts, street lights and over-duty circuit breakers were included in the RPM in the 2005 Rate Plan, and the Company "has incurred no penalties for any special projects since these were established in 2005." (2033). The SIP also acknowledged this performance record during cross examination. (4078). Because of the Company's fully adequate performance, even if an RPM is maintained, these measures should now transition to standard-only measures without penalties and the Company should continue to report its performance to the Commission. (1894; 2032).

A penalty mechanism is not required to achieve the special project performance levels that Staff seeks. The Company's compliance with the requirement in the 2005 Rate Plan to "energize at least 85 percent of new streetlights within a 90-day period and all new streetlights within 6 months" demonstrates this point very well. Significantly, this is a "special project" in the rate plan with a compliance standard that is not enforced with a penalty. (2031-2032).

(i) No-Current Street Lights and Traffic Signals

Ignoring the Company's past compliance with this measure, Staff proposes to increase the negative adjustment for the special project "No-Current Street Lights and Traffic Signals" from $1 million to $1.5 million for the winter month period performance and likewise for the summer month period performance. (4053). There is no reason to increase the penalties for this special project. Con Edison has met the summer and winter performance targets for this special project and has incurred no penalties since these targets were established in 2005. (2032-2033). Not only has Staff not demonstrated that an adjustment is necessary, but also they have failed to justify the amount of the adjustment by showing a nexus between the amount of the increased negative rate adjustment and the targeted performance goals. Staff's sole justification for this increase is a desire for uniformity with other penalties in the special project category and not because Staff has provided any reason that a higher negative rate adjustment is required to achieve the targeted goals. This special project, like the other special projects should now transition to a standard-only measure without penalties.

(ii) Over-Duty Circuit Breaker Replacements

The special projects penalty mechanism for area substation circuit breaker replacements is counterproductive to the reason for the mechanism stated in Exhibit 275, p. 19, *i.e.*, "to enable the installation of synchronous generators [for] the use of DG [distributed generation] to address a variety of concerns." The installation of synchronous generators in a network requires that all over-duty breakers in the supply substation be replaced since a substation is not protected from over-duty fault currents from synchronous generators until all the station's breakers are replaced with upgraded breakers. Thus, the Company's replacement program focuses on replacing all distribution feeder breakers in a substation. A breaker replacement requires that its bus section

be taken out of service, and breaker replacements are ideally performed by bus section, so that all breakers on a bus section can be replaced during the bus section outage due to the difficulty in obtaining a bus section outage. Typical breaker replacement for a bus section requires a 9 to 14 day outage, and other outages in the substation are typically prohibited during this time in order to maintain substation reliability. The penalty mechanism encourages the Company to focus on bulk breaker replacements at whatever substation a bus section outage can be obtained instead of completing each substation with over-duty breakers. Accordingly, continuation of the penalty mechanism for over-duty circuit breaker replacement makes no sense because it does not support the stated goal. (2035-2036).

Staff's Panel proposes a one-year target for circuit breaker replacements that will make it even more difficult for the Company to focus on finishing a substation. In Exhibit 275, p. 19, Staff proposes a revenue adjustment of $3 million per year for the Company's failure to "replace a target of at least 60 over-duty circuit breakers during the rate year." While the 2005 Rate Plan RPM also includes a replacement target of 60 breakers per year, the revenue adjustment is $100,000 per breaker not replaced is measured against a <u>two-year</u> target of 120 total breakers over the two year period ended March 31, 2008.[205] (2033). Staff's proposed one-year focus will further encourage the Company to focus on bulk breaker replacements at whatever substation a bus section outage can be obtained.

The Company's revenue requirement in this proceeding reflects $8.8 million per year to continue its over-duty circuit breaker replacement program at the level of at least 60 replacements per year. During the rate year ended March 31, 2007, Con Edison replaced 62

[205] Before Exhibit 275 was marked for identification during the hearing, Staff modified page 19 of the exhibit to delete a proposal to penalize the Company $3 million for failure to replace even one circuit breaker less than 60 in a year. Con Edison's Infrastructure Investment Panel addressed this proposal before it was withdrawn. (2035). However, this testimony discussing the counterproductive nature of the circuit breaker performance measure remains applicable to Staff's revised exhibit.

over-duty circuit breakers, and system conditions permitting the Company expects to replace at least 60 in the current rate year. Moreover, during the rate year ended March 31, 2006, when there was also a 60 breaker replacement target but no penalty was applicable, the Company replaced 113 over-duty breakers. Although 113 is an exceptional annual number for this program (favorable weather conditions and the renovation of the White Plains substation, as part of the Company's obsolescence program [23 breakers] contributed), these replacements over the last two rate years demonstrates the Company's commitment to circuit breaker replacement without the need for a penalty mechanism. (2034).

The circuit breaker special project should transition to a standard-only measure with standards that better accommodate the purpose of the mechanism.

4. <u>Restoration Category</u>

Staff's Panel proposed a "restoration mechanism" to penalize the Company $5 million each time that it fails to meet a time period for the restoration of service to customers following an outage event. (4050-4052). The time period for restoring service would vary with the classification of the event that causes the service outage. For the overhead system, the mechanism uses six storm-event classifications and associated service restoration timeframes based upon the estimated restoration times in the Company's Overhead Storm Plan for the Bronx Westchester Region. For the underground network system, Staff proposes that the Company "provide an estimated restoration time for underground events to be included in its emergency plan." (4050-4052; Exh. 275, pp. 9-10).

Con Edison opposes the Restoration Mechanism not only for the reasons supporting its stated opposition to penalty mechanisms, but also for a variety of reasons specific to the restoration mechanism itself. The proposed "restoration mechanism" is the wrong approach at

the wrong time for regulatory oversight of emergency preparedness and storm restoration in New York. As recently as June 2006, Staff acknowledged that it needs to "clarify[ing] Staff's expectations for utilities' emergency planning, preparedness, and plan execution." In an October 2007 audit report on Con Edison's emergency management program, the Commission's auditor recommended that the Commission enhance "regulatory oversight of electric utility emergency preparedness and storm restoration" by a focus on "best practices," with no mention of penalty mechanisms. [206]

a) Regulatory Oversight of Emergency Management Should Focus on Performance Standards Rather Than the Narrow Measure of Restoration Time

In the event that the Commission decides that it should regulate emergency management through the use of performance standards, it cannot reasonably adopt the standards proposed by Staff. There currently exist no general performance standards in emergency management.

According to Staff, the restoration mechanism "uses restoration time as the means to measure the Company's performance" in restoring service to customers following a storm. (4050). However, Staff makes no showing that restoration time is an appropriate or adequate measure of utility performance in responding to storm-related outages. Indeed, no measures whatsoever have been developed in New York for assessing utility storm response performance.

In June 2006, Staff issued a report on the Company's performance following the January 18, 2006 storm that interrupted service to 100,000 electric customers in Westchester County, 60,000 of whom were in Con Edison's service area ("June 2006 Report"). In that report, Staff tacitly acknowledged that it does not utilize and has not developed performance standards to

[206] Case No. 06-M-1078, Proceeding on Motion of the Commission to Audit the Performance of Consolidated Edison Company of New York, Inc. in Response to Outage Emergencies, Notice Inviting Comments, October 25, 2007. The audit report, titled "Independent Audit of Consolidated Edison Company Electric Emergency Outage Response Program for the New York State Department of Public Service," ("Audit Report") can be found on the Commission's web site at http://www.dps.state.ny.us/06M1078_audit.htm.

measure storm response and that it needs to clarify to utility companies "Staff's expectations for utilities' emergency planning, preparedness, and plan execution." The June 2006 Report states:[207]

> [T]here are currently no performance standards for storm response in New York State, and … [Staff] is not aware of any such standards for major storm events in other parts of the country. Staff will further investigate the industry to determine if there are any mechanisms in place or that can be developed to measure restoration performance following a major storm. This evaluation should be useful in further clarifying Staff's expectations for utilities' emergency planning, preparedness, and plan execution.

In addition to recommendations that are intended to improve the Company's emergency preparedness and response to electric outage events, the Audit Report calls for the Commission to enhance "regulatory oversight of electric utility emergency preparedness and storm restoration" which the audit report found to be "considerably more extensive and proactive in nature in regions routinely affected by hurricanes and tornadoes."[208]

The Audit Report recommended that the DPS adopt "several regulatory practices and procedures," but the Audit Report did not recommend that the Commission adopt a performance mechanism of any type, much less one focused solely on restoration time, to promote effective electric outage response. Instead, the Audit Report recommended a considerably more sophisticated approach for regulatory oversight of emergency preparedness and storm restoration in New York. The Audit Report made the following "three key observations that have generic application in New York:"[209]

> Emergency Preparedness and Storm Restoration should be a statewide, collaborative all-utility process.

[207] June 2006 Report, p. 13.
[208] Audit Report, p. 234.
[209] Audit Report, p. 240.

> The Commission's directive for a "best practice" standard sets the tone for utility participation and compliance.
>
> Emergency Preparedness should be proactive creating a better understanding of utility responsibilities and expectations.

To promote a proactive regulatory role in "creating a better understanding of utility responsibilities and expectations" the Audit Report recommended that the Commission "[c]onsider, through the DPS Staff, implementation of a collaborative program including all of the electric, gas and telecommunications utilities within its jurisdiction to develop best practice emergency preparedness and major outage restoration programs."[210]

The restoration mechanism is the wrong approach at the wrong time for regulatory oversight of emergency preparedness and storm restoration in New York. The approach is wrong because Staff should be developing a "best practice standard [that] sets the tone for utility participation and compliance" for utility emergency preparedness and response. Yet, instead of looking to best practices in emergency management, the Panel proposes a penalty mechanism, setting a punitive tone sharply in contrast with the comprehensive measures being practiced by regulatory authorities in other states. The Audit Report discusses in detail the emergency management regulatory oversight approaches used by the state commissions in Florida and Missouri, which "stood out for their proactive approach toward ensur[ing] best practices."[211] In contrast to the Panel's proposed penalty mechanism, the Audit Report developed a list of 41 "primary categories of major storm restoration planning and execution activities" that should be the focus of regulatory oversight through a "best practice standard." The Audit Report

[210] Audit Report, p. 226.
[211] Audit Report, pp. 220-226.

demonstrates that effective regulatory oversight of emergency management requires comprehensive standards rather than blunt punishment focused on a narrow objective.[212]

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[212] The Audit Report (pp. 238-239) identified the following primary categories of major storm restoration planning and execution activities" that should be the focus of regulatory oversight:

System Storm Center & Operations

Having a robust Crisis Management Plan & sticking to it.
Employees are trained & ready to respond in their roles.
Storm Tracking & Notification System.
Damage assessment & repair teams trained & ready to respond.
Strong Mutual Assistance Agreements - tree trimming & lineman.
Continuous effective communications (hardened facilities).
Continuous prioritization of restoration focus.
Repairing health, safety, Fire, Police, water and sewer facilities quickly.
Repairing backbone systems.
Identifying and 'making safe' downed lines.
Scheduling of necessary personnel in operations.
Maintenance & Replacement Programs for critical infrastructure.
Holding regularly scheduled, but brief, update meetings to discuss status and goals.
Maintain flexibility for changing circumstances.
Presence at Emergency Operations Centers in affected areas.

Staging & Logistics

Equipment inventory, re-supply provisions & distribution.
Advance preparation of equipment supply chain.
Identify potential Pinch Points and address them.
Crew safety and system orientation training.
System mapping and restoration procedures.
Meal planning and distribution.
Truck fueling and security.
Soiled clothing pick-up, laundry, and return.
Staging site agreements with shopping centers, hotels, schools, and airports.

Corporate Communications

Pre-storm checklist for customers.
Consistent message with best available information.
Regular communications with all media.
Arrange press tours of damaged areas.
Educate consumers of reasonable expectations.
Specific communications with large customers.
Web site information for those with access to computers.
Call-Center people having access to current status information.
Generator use safety notifications.

Community & Customer Relations

Up-to-date contact information and keep state and local officials in loop.
Listen to local government and county agency priority needs.
Work closely with local officials in communicating status.
Conduct regional community disaster response workshops.

Looking Back & Looking Forward

Corporate culture that seeks feedback on what went well and what didn't.

The Audit Report itself cautions against the narrow focus on restoration time that the Staff Panel proposes. The concept that this single metric can promote the success of an emergency management program is discredited by the following conclusion in the Audit Report:[213]

> Getting the lights back on is not sufficient in Con Edison's current environment, where emergency management is under a new set of microscopes. As a result, the narrowly defined view of emergency management must give way to a more holistic perspective in which Con Edison's measures of performance cover many elements of an emergency and not just the physical restoration work.
>
> The transition [at Con Edison] to an holistic view of outage management (as opposed to a narrow, technical, physical restoration viewpoint) is well underway but remains a work in progress.

The timing of Staff's proposal is wrong because Staff, as stated in its June 2006 Report, needs to "clarify[ing] Staff's expectations for utilities' emergency planning, preparedness, and plan execution."(June 2006 Report, p. 13). In this regard, it is particularly instructive to recall that the Commission established a Reliability Standards proceeding to adopt reliability performance standards a couple of years <u>before</u> beginning to approve rate-plan settlement agreements that incorporated reliability performance mechanisms based on those standards.[214] However in this case Staff proposes a new restoration mechanism to enforce performance that is not defined by any regulatory standards for measuring utilities' emergency planning, preparedness, and plan execution because to date, as Staff has acknowledged the standards exist.

Root cause analysis of major problems and assessment of ways to improve in the future.
Look for ways to reduce future storm impacts on system.
Workforce recognition and recovery

[213] Audit Report, pp. 17-18.

[214] Case No. 90-E-1119, Proceeding of the Commission to consider establishing standards on Reliability and Quality of Electric Service, Order Adopting Standards on Reliability and Quality of Electric Service, July 2, 1991 ("Reliability Standards proceeding").

In the Reliability Standards proceeding, Staff's memorandum stated that the standards "would require each electric company to develop programs that detail specific actions each company will take to ensure that adequate service is provided."[215] But it was only last month that the Audit Report was issued with 62 recommendations for specific planning actions that the Company needs to take to enhance its emergency readiness, management and response.

Establishing a restoration performance mechanism is at the very least premature until the Company has had an opportunity to address the issues identified in the Audit Report and implement its recommendations. The implicit purpose of the audit recommendations is to provide for an emergency management program at Con Edison that appropriately prepares for and responds to service outages and does not require the enforcement mechanism proposed by Staff.

Ironically, Staff witness Eng recommends disallowance of four Company programs related to emergency response on the grounds that the Company should first act on the audit recommendations, but speaking as part of the Staff Infrastructure Panel, he accepts that the Company should be subjected to an emergency penalty mechanism before it has had an opportunity to act on the recommendations. (4196).

b) Staff's Wholesale Denial of the Company's Emergency Management Funding Increases Is Inconsistent With Establishing a Penalty Mechanism for Restoration Performance

The timing of the SIP's proposal is also wrong because Staff proposes at the same time to deny the Company the resources that it requires to improve its emergency management program. Staff proposes to deny (subject to future consideration based upon the Company's implementation of Audit Report recommendations) or reduce many program changes that

[215] Case No. 90-E-1119, Order Instituting Proceeding and Inviting Comment on Proposed Standards, December 19, 1990.

directly impact the Company's ability to restore customers expeditiously. Staff Witness Eng proposes to eliminate the Coastal Storm Mitigation Plan which seeks to eliminate the risks associated with storm surge. (4193-4194). He also eliminates the expansion of the Electric Operations Emergency Management Group which is focused on developing and enhancing processes throughout Electric Operations to reduce the potential for and minimize the duration of outages and communicating openly and effectively during outage events. (4191-4192). Mr. Eng also rejects the Control Center Screening Group, an organization that would help prioritize restoration work and enhance restoration times. (4192-4193). Further, the SIP proposes to reduce eleven Storm Hardening program changes that the Company proposed. The Storm Hardening programs are designed to minimize the number of customers impacted by system events. Staff's denials or reductions of emergency management resources and funding, after Staff has been critical of the Company's emergency response, are certainly inconsistent with Staff's proposed restoration penalty mechanism.

c) <u>Weaknesses in Staff's Restoration Mechanism</u>

The proposed restoration mechanism itself has several weaknesses that make it impractical for measuring restoration performance.

First, the Panel proposes to measure the Company's performance using the Company's storm classification matrix that was never intended to set a firm time for the complete restoration of service. The storm classification matrix provides guidance for the level of staffing resources that will be initially deployed in anticipation of an event. It does not establish the actual time required to restore service. (2005).

The testimony cites only a portion of the classification matrix – and not the portion that pertains to initial resource deployment. The matrix actually contains the following components: (2004-2005).

- six storm classification levels;
- wind and rain characteristics of each storm classification;
- numerical range of potential customer outages for each storm classification level;
- estimated service restoration time for that number of customer outages due to that class of storm;
- anticipated deviations depending on event characteristics such as time of year, tree cover, and recent weather; and
- resources that will be initially mobilized and deployed to repair damage and restore customers.

The number of customer outages and the time to complete service restoration are obviously estimates based on past experience with outages from different categories of storms. (2004-2005).

The weather forecast is the main driver in determining initial classification of the expected storm, the number of customers that might experience outages, and the level of the initial mobilization. Each preliminary storm classification includes a range of potential customer outages and a target for restoration time for a hypothetical storm of that class based on prior storm-event information. The initial estimate of resources required for restoration work reflects the preliminary classification of the event based on weather forecasts before the storm occurs. However, because weather forecasts can be inaccurate and each storm event has unique characteristics, the estimated customer outages and restoration times serve only as a guide for initial mobilization and deployment pending the Company's assessment of actual damage and outages. Adjustments are made to the initial deployed resources in response to actual customer interruptions and reported damage to the distribution system as that information is received.

(2005-2006). After a more detailed understanding of the unique characteristics of a storm are known, a more accurate global estimated restoration times can be established.

Another weakness of the restoration mechanism is its setting of the severity of a storm, and thus the applicable restoration target, by the Company's initial classification of the event. This approach misses entirely the key factor that drives the restoration time for the outages – the damage actually sustained during the event. (1999). Each storm has its own characteristics resulting in differing levels of lightning strikes, ground saturation from rain, fallen tree limbs or uprooted trees, and sustained winds. The extent of damage is predicated on the characteristics of the storm. For instance, the tornados and the Nor'Easter experienced by Con Edison during 2007 resulted in extensive physical damage but due to the localized impact area, the number of customers without service was minimized resulting in a lower storm classification level and relatively short estimated restoration times on the storm classification matrix. However, the matrix classification's estimated restoration time did not account for the heavy localized damage that needed to be repaired to restore service to those customers. (2000-2001).

Staff's proposed restoration mechanism also fails to account for overhead system designs that minimize the number of customers interrupted due to a storm despite the amount of system damage. Overhead auto-loop feeder designs and KYLE switches are designed to automatically isolate damaged portions of the overhead lines and almost immediately restore power to customers not on the isolated lines. However, while these designs significantly reduce the number of customers affected by a given level of storm damage, they do not reduce the damage that must be repaired before the customers on the isolated lines can be restored. Thus, tying a restoration mechanism to a storm classification derived from customer outage count does not appropriately account for the amount of work and time required to restore customers to service.

Fewer customers without service do not mean less time needed to restore service. (2001-2002). Ironically, these same circuit designs contribute to Con Edison's radial SAIFI performance which is nearly twice as good as the next best utility in New York State.

Moreover, the restoration mechanism will conflict with the Company initiatives to install sectionalizing devices to further segment the overhead system and reduce the number of customers affected by an event. (1836). These devices reduce customer outages but not the amount of damage to be repaired to restore affected customers.

Nor does the restoration mechanism adequately account for the variability and differing characteristics associated with emergencies and the resulting damage. The SIP's states, "[T]here needs to be clearly defined consequences to the Company for failing to provide good customer service...Targets are set at levels that indicate problems or degradation in service." (4047). Yet, the proposed restoration mechanism does not appropriately account for frequently encountered factors wholly outside the Company's control that are not indicative of problems with the Company's emergency response but nonetheless inhibit the restoration of customers. These factors include extreme weather conditions preventing restoration efforts and access restrictions caused by local conditions. Further, a number of independent factors not fully within the Company's control influence the Company's ability to plan, prepare for, and respond. These include weather forecasting limitations, municipal and private tree trimming restrictions, mutual aid availability, ability to compel local governments to properly mitigate identifiable risks, and requests by local government officials to isolate areas and perform activities, such as tree clearance, that do not directly restore service to customers. (2004; 2006-2007).

d) <u>Counterproductive Outcomes of Staff's Restoration Mechanism</u>

In addition to these deficiencies, the SIP's restoration mechanism will have counterproductive outcomes.

The restoration mechanism is inconsistent with Company storm response initiatives that are designed to minimize the impact of storm events on the public as a whole. The Company has made significant strides to improve its responsiveness in this area based upon benchmarking with other utilities and interaction with local governments. For instance, during recent events, the Company has allocated resources to establish "normalcy" in impacted areas, by allocating significant resources to restore traffic lights, restoring service to schools, and opening roadways blocked by trees. While these decisions may not have restored customers in the most expeditious manner, their expedited completion contributed to addressing other important needs of the affected communities, including safety. The proposed restoration mechanism would encourage the Company to focus exclusively on the restoration of customers rather than working collaboratively with local municipalities/boroughs to address local municipal/borough concerns. (2010).

Utilities rely on the resources of other utilities ("mutual aid") to help repair storm damage and restore service following more serious storm events. However, utilities are under no obligation to provide mutual aid resources. (2008). During widespread storm events that impact multiple utility service areas, utilities usually address the majority of repairs and outages on their own systems before releasing crews to other utilities. Yet in more serious storm events, the proposed restoration mechanism would require Con Edison to rely upon other utilities' willingness to support its restoration efforts and could subject the Company to a $5 million penalty if mutual aid resources were not adequate.

The prospect that Staff will seek to impose a restoration penalty mechanism on other utilities will further induce other utilities to mitigate their risk completely and delay sending mutual aid until all of their own customers are restored. (2008). This mechanism also will have a chilling effect on Con Edison's ability to provide mutual aid to other New York utilities.

Staff's proposed restoration mechanism is a poor regulatory policy out of step with regulatory best practices and is internally flawed and counterproductive. An emergency management performance mechanism is not warranted at this time as Con Edison implements the recommendation of the Audit Report to improve its emergency preparedness and response. Staff's proposal should be denied.[216]

5. <u>Customer Service Performance Incentive Mechanism ("CSPI")</u>

Staff's Customer Service Panel recommends notably continuing the CSPI from the 2005 Rate Plan, but with the following modifications to the ONIM provisions of the CSPI: (3845-3846)

- The Company's financial exposure would be doubled from $150,000 to $300,000 for each ONIM activity that is either not completed within the prescribed time period or does not contain the required information;
- An additional activity would be added to the list of notification activities – holding conference calls to brief public officials; and
- The total amount at risk under the ONIM would be increased from $4 million to $8 million, thus increasing the total amount at risk under the CSPI from $36 million to $40 million.

[216] In any event, a restoration performance mechanism should not be implemented before the Company implements appropriate Audit Report Recommendations and procures necessary resources. As customer expectations regarding electric service reliability increase, as the frequency and severity of weather related events grow, and as other utilities face the prospect of penalty mechanisms for restoration performance, Con Edison's reliance upon mutual aid resources may no longer be an adequate solution. Consistent with the recommendation of the Audit Report, Con Edison is identifying the necessary increases in internal resources, including field staffing, required to meet the needs and expectations of customers. The Company's filing in this proceeding reflects several programs to help to address this concern, but Staff's Panel recommends the elimination of these programs at least pending the Company's implementation of Audit Report recommendations. The Company will likely propose additional resources beyond those presented in this proceeding in order to implement the audit recommendations.

CPB witness Elfner similarly proposes to add a new activity for holding conference calls to brief public officials and to increase the ONIM penalties, recommending that they be increased by a factor of no less than 10. Mr. Elfner also proposes adding new criteria regarding the accuracy of the Company's outage estimates. (4709-4710).

These proposals should be rejected. Staff's Consumer Services Panel points to no deficiency as reason to continue the CSPI. The continuation of the CSPI is not needed. The increased ONIM penalty amounts proposed by Staff and CPB are arbitrary. Staff proposes to double the ONIM penalties; CPB proposes a ten-fold increase; neither provides a rationale why their proposed increase is appropriate. (2038).

The ONIM has been in effect since 2002. (4707).[217] Mr. Elfner cites the potential for a $300,000 penalty arising out of the Long Island City ("LIC") event in which Staff's LIC Investigation Report found that the Company did not meet two of the 13 performance ONIM communication activities, although the Commission has not issued its determination. (4709). The Company fails to understand how the failure to meet two of 13 ONIM communication activities over the last five years warrants an increase in the penalty amounts. The more rational conclusion, to the extent except the Commission believes that such penalty mechanisms have a positive effect on the Company's communications, is that the ONIM has been done its job over that last five years and no changes to the ONIM are warranted.

To date, the Company has demonstrated that it can and will implement changes to its outage communication performance without the need for negative financial incentives. Thus, the Company has already implemented the recommendation in Staff's Westchester Outage Report

[217] Case No. 00-M-0095, Order Approving Outage Notification Incentive Mechanism, April 23, 2002, pp 3-6. The ONIM established six communication that each have a timeliness and content requirement, plus a seventh communication activity – 13 communication activities in all.

for conference calls to brief public officials about the status of restoration, and there is no need for an incentive mechanism for this activity. In the Commission's July 20, 2007 "Order Implementing Recommendations" in Case 06-E-0894, the Commission found that "nearly all of Staff recommendations are being adequately implemented by Con Edison."[218] This includes the conference call recommendation. Indeed in that Order, the Commission stated three separate times that it is "generally satisfied: with the Company's implementation of Staff's recommendations from the Westchester and the LIC reports."[219]

Further, the Audit Report examines the Company's communications with public officials during emergencies and found that "Con Edison has worked diligently to establish effective communications with the numerous public entities that it deals with during outage events."[220] The Audit Report confirms that Staff's conference call recommendation is already in effect. The report describes the process in detail as follows:[221]

> In Westchester County, Con Edison now conducts a daily telephone conference call for public officials during the days that service restoration is ongoing. The Company notifies public officials of the time and the call-in number for the conference call. During the telephone conference, the Company will provide the latest status on service restoration including the number of customers interrupted, number of customers still out of service, municipalities and districts affected, number of crews working, available estimated restoration time, and dry ice distribution locations. If the call is not feasible, daily phone contacts with elected officials in the affected areas will be made.

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[218] 06-E-0894 and Case 06-E-1158, Order Implementing Recommendations, July 20, 2007, p. 10.
[219] Case 06-E-0894 and Case 06-E-1158, Order Implementing Recommendations, July 20, 2007:

> We are generally satisfied with Con Edison's progress in implementing the recommended improvements. (p. 5)
>
> The Commission is generally satisfied with Con Edison's cooperation in implementing Staff's recommendations. (p. 9)
>
> We are generally satisfied with Con Edison's efforts to implement recommended improvements. (p. 26)

[220] Audit Report, p. 169.
[221] Audit Report, p. 170

Our point here is that with the conference call procedure already in effect and the Commission expressing general satisfaction with the Company's progress in this communication area, it is not necessary at this time to enforce ongoing compliance with a penalty measure. The Company has no objection to reporting on its ongoing compliance to Staff. The Commission may take appropriate action if it determines that the Company's performance does not "measure up" to its expectation. Accordingly, Staff's and CPB's recommendations for adjustment of the ONIM should be denied.

6. <u>Manhole Maintenance</u>

Local 1-2 claims that congestion in the Company's manholes has a resulted in a "questionable history" of manhole incidents over the last ten years. (5039). Local 1-2 recommends an incentive mechanism -- which the Company presumes to mean a penalty -- to encourage the Company to increase manhole maintenance and eliminate congestion. (*id.*). Local 1-2's allegations are unfounded and its recommendation is unduly vague, as it offers no proposal that may be reasonably evaluated by the Company or the Commission. Therefore, Local 1-2's recommendation should be rejected.

Local 1-2 mischaracterizes the relative frequency with which manhole incidents occur and the cause of such incidents. Less than one percent of the Company's 270,000 underground structures experienced a manhole incident over the last eight years. (2039). Although Local 1-2 suggests that manhole congestion is the primary cause of such incidents, the Company consistently sees a strong correlation between the amount of salt distributed by the City and the number of underground structure events. (*id.*).

The Company needs no negative encouragement to properly maintain its underground facilities. Over the last two years, 120,000 underground structures have

been inspected as part of the Company's secondary reconstructing project. (2040). Out of these inspections, less than half a percent of the structures required enlargement. (*id.*).

Moreover, there are significant gaps that preclude any meaningful assessment of Local 1-2's recommendation. Local 1-2 does not explain or define what it means by "congestion." (*id.*). More importantly, Local 1-2 does not offer a specific proposal that parties and the Commission may evaluate (*id.*). The Staff Infrastructure Panel similarly testified that they cannot support Mr. Koda's recommendation because of the absence of specific details regarding how the mechanism and thresholds would work. (4062).

Local 1-2's allegations concerning the Company's performance relating to manhole incidents and manhole congestion are unfounded and since Local 1-2 made no proposal to address these alleged concerns that may be reasonably evaluated, the Commission should reject Local 1-2's recommendation.

X. EMBEDDED COST OF SERVICE STUDY/REVENUE ALLOCATION

A. Cost and Revenue Allocation Among the Service Classes Including NYPA

1. Con Edison's Position on Cost and Revenue Allocation Of The Proposed Increase To The Service Classifications

The Electric Rate Panel performed an embedded cost of service ("ECOS") study analyzing costs and revenues associated with the Company's delivery system, *i.e.*, transmission, distribution, and customer-related cost categories or functions, and also included cost categories related to competitive functions (the electric procurement function, competitive metering functions, the receipts processing function and the printing and mailing a bill functions). The ECOS study covers costs for the calendar year 2005 and electric revenues based on current delivery rates, which went into effect April 1, 2007. The study analyzed classes of customers

corresponding to service classifications ("SCs") contained in the Company's electric rate schedules, including retail access customers, customers of NYPA served by Con Edison under the PASNY No. 4 schedule, and customers served under the Economic Development Delivery Service ("EDDS") No. 2 schedule. The results of the ECOS study are expressed as Total Company ("total system") and class rates of return. Based on past practice, class revenue responsibilities were then measured with respect to a ±10% tolerance band around the total system rate of return. Classes would not be considered "surplus" or "deficient" if the class ECOS rate of return falls within this tolerance band. Classes that fall outside this range would be either surplus or deficient by the revenue amount, including appropriate state and federal income taxes, necessary to bring the realized return to the upper or lower level of the band. As shown on Table 1A of Exhibit 7, NYPA has a revenue deficiency of $30.2 million and the Con Edison classes and EDDS have revenue surpluses of $30.1 million and $0.1 million, respectively. (177-180).

Based on these indications from the Company's 2005 ECOS, Rate Year T&D delivery revenues at the current April 1, 2007 rate level for the Con Edison classes, NYPA and EDDS were realigned to recognize the corresponding revenue surpluses and revenue deficiencies applicable to each class.

The Electric Rate Panel then allocated the increased delivery revenue requirement for the first rate year of $1.225 billion, including gross receipts taxes, among Con Edison's customers, NYPA delivery service and EDDS as follows (204-209):

- The portion of the increased revenue requirement associated with increases in MAC costs ($53.0 million) and purchased power working capital ($5.8 million) was allocated directly to Con Edison's customers and deducted from the increased delivery revenue requirement.

- The remainder of the increase of about $1.166 billion representing the T&D related delivery revenue increase was reduced by gross receipts taxes ("GRT") of about $33 million, and the resultant $1.133 billion was allocated among Con Edison's customers, NYPA delivery service and EDDS in proportion to each group's rate year realigned T&D revenues. Using realigned revenues to allocate the increase maintains the underlying ECOS study indications.

- The increase allocated to NYPA delivery service ($122.1 million) was increased by the $30.2 million deficiency from Table 1A to determine the total revenue increase to NYPA of $152.3 million.

- The increases allocated to Con Edison customers ($1.003 billion) and EDDS customers ($7.6 million) were reduced by the surpluses shown on Table 1A of $30.1 million and $0.1 million, respectively, in order to determine the final T&D related delivery revenue increases of about $973 million and $7.5 million, respectively.

- The T&D related delivery revenue increase of $973 million allocated to Con Edison customers was then increased by $51.4 million, excluding GRT, associated with an increase in the MAC revenue requirement and $5.6 million, excluding GRT, associated with purchased power working capital for a total increase of $1.030 billion.

- For later use in rate design, the rate year T&D related delivery revenue increases for Con Edison, NYPA and EDDS were restated on the basis of the twelve months ended December 31, 2005, *i.e.*, the historical period for which detailed billing data are available. This was accomplished by dividing each class's Rate Year non-competitive delivery revenue increase by a revenue ratio equal to each class's Rate Year T&D revenue divided by historical period T&D revenue.

In summary, based on the foregoing revenue allocation, the proposed rate-year delivery revenue increases, including GRT, for Con Edison customers, NYPA delivery service and EDDS service are $1.060 billion, $157 million, and $8 million, respectively. (Exhibit 9, Schedules 9-11).

2. <u>Staff Position on the ECOS Study</u>

The Staff Rate Panel accepted the Company's classification and functionalization of costs in the ECOS Study (4879). Staff limited its comments on the study to propose the use of a 15 percent tolerance band to determine class surpluses and deficiencies. Staff supports this

incremental 5 percent adjustment to the tolerance band as a means of addressing its criticism of the Company's proposed weighting of Non-Coincident Peak Demands ("NCP") (75 percent) and Individual Customer Maximum Demands ("ICMD") (25 percent) used in allocating low tension distribution demand costs to the SC 1 and SC 7 residential classes. (4888-4889). Staff does not take issue with the averaging of NCPs and ICMDs for non-residential classes and indicates that this averaging as presented by the Company recognizes the existence of load diversity on the low tension system. (4886).[222]

The fact that Staff does not agree with the Company's methodology of weighting NCPs and ICMDs for the SC 1 and SC 7 residential classes does not provide a basis for a 5 percent adjustment to the tolerance band. (281). The Electric Rate Panel explained that there was no link between the NCP/ICMD weighting and an incremental five-percent increase in the tolerance band. (349). Staff's five-percent adjustment to the tolerance band, while not changing the class rates-of-return, widens the band around each class's actual return. In contrast, a change in allocation methodology would directly impact individual class ratesofreturn, thereby changing their relative positioning. For example, an allocation methodology that more heavily weights ICMDs than that presented in the Company's ECOS study would adversely impact residential customers.

Staff's recommendation to increase the tolerance band in combination with Staff's rejection of the Company's 75 percent/25 percent weighting is puzzling at best and is not necessary to support their recommendation that the Company develop a study that would

[222] The Company argues for a 75%/25% weighting due to the diversity of residential loads within apartment buildings. (266). Staff's criticism of the Company's weighting of NCPs and ICMDs for residential classes is based upon the lack of a supporting study. (4888). Staff argues that "some recognition of the unique diversity of the SC1 and SC7 customer class is necessary, but that without a study, the Company's 75%/25% is not warranted." (4886).

establish the weighting of NCPs/ICMDs for residential classes. The Company maintains that the use of a 10-percent tolerance band is appropriate.

3. NYPA's Position on The ECOS Study

NYPA believes that it is "inappropriate to use Con Edison's 2005 ECOS in this proceeding" and claims that the study's "results do not follow the most basic cost-causation principles." (4626). NYPA recommends that the study should be dismissed and not used for revenue allocation. Absent outright dismissal of the study, NYPA proposes several modifications to the study that serve to decrease the NYPA deficiency. The adjustments are to the following topic areas:

a. Use of Allowable Rate of Return vs. ECOS Rate of Return

b. Coincidence Factors – SC 65 and SC 85

c. Allocation of HT costs to SC 7, 12 Conventional, 12 TOD

d. Allocation of the Low Tension System – Averaging of NCPs/ICMDs

e. R&D Costs

f. Use of Historic Cost Study – 2005 costing disproportionate to future investment which is more heavily weighted towards distribution

g. Tolerance Band

a) Use of The Allowable Rate of Return Rather Than The Return Generated By The ECOS Study

The ECOS study reflects 2005 conditions adjusted for rates effective April 1, 2007. The ECOS study shows the relative position of the various classes in relationship to the system average return. From this starting point and following past Commission practice, Con Edison determines the surpluses or deficiencies based on a plus or minus 10 percent tolerance band around the system rate of return. (178-179).

NYPA recommends using the allowed rate of return of 8.08 percent from the current agreement, rather than the calculated rate of return in the embedded study of 9.03 percent, to develop surpluses and deficiencies. The 9.03 percent return is the result of a 2005 embedded cost-of-service study where sales, costs and class allocations are aligned. To introduce the allowed return would require making pro-forma adjustments to the study in order to align costs, revenues and allocation factors. (258).

Further, even if such a return adjustment were proper, to be fair to all classes, it would be necessary to reduce all class revenues to reflect the lower rate of return. In adjusting to the allowed rate of return, NYPA incorrectly made an apples-and-oranges comparison by leaving its return at the filed ECOS level of 6.5 percent and comparing it to the 8.08 percent allowed return, thus giving the appearance of a much lower NYPA deficiency. To use the NYPA Panel's allowed rate-of-return approach, without maintaining the class relationships resulting from the ECOS study, results in a meaningless calculation. By properly adjusting the NYPA revenues to reflect the overall lower return, the NYPA deficiency would be lowered from the Company's filed $30.2 million to $28.6 million rather than the $14.3 million (258-259) shown on Exhibit 308, page 1 of 15. Notwithstanding, even with a comparison that properly uses an allowed return, the Company still disagrees with superimposing any rate of return into the 2005 study because, as explained above, it creates misalignment between costs and revenues.

b) <u>Coincidence Factor Calculation for SC 65 and SC 85</u>

In Exhibit 308, Page 4 of 15, NYPA recalculates the coincidence factor for traction and substation loads under an erroneous assumption regarding the manner in which these loads are billed. NYPA's calculated reduction in the coincidence factor and associated reduction in NYPA's cost responsibility incorrectly assumes that each station is billed on a non-coincident

basis. NYPA is in error. These customer groups are billed on a coincident basis. For example, the Staten Island Rapid Transit maximum billing demand is based on the coincident load of the component stations. NYPA's adjustment to the coincidence factor for SC 65 and SC 85 is invalid. (259-262).

c) <u>Allocation of HT costs to SC 7, 12 Conventional, 12 TOD</u>

NYPA takes exception to the long standing treatment of high tension cost allocation to residential heating loads. These customers are winter peaking and are not isolated to any particular high-tension geographic area so as to make that area winter peaking. It is, therefore, reasonable to allocate their high-tension costs, which serve a mix of customer classes, on the basis of summer demands. (262). Although NYPA makes no reference to the treatment of its multiple dwelling heating customer group, it should be noted that the Company's historical treatment of residential heating loads has also been applied to NYPA's residential heating customers. To alter this methodology to allocate high tension costs on the basis of the winter peaks of these heating classes would adversely impact residential customers.

d) <u>Allocation of the Low Tension System</u>

The NYPA Panel proposes to allocate the low tension system using ICMD instead of the Company's use of an average of NCPs and ICMDs. (4635). NYPA proposed this methodology in several prior cases, *e.g.*, Case Nos. 94-E-0334 and 04-E-0572. Beginning with Case No. 96-E-0897, the Company changed its methodology of using 100 percent NCPs and introduced averaging of NCPs and ICMDs to reflect the fact that both of these allocators play a role in the design of the secondary system. In addition, NYPA offers no new theory to support its position regarding the sole use of the ICMDs to allocate low tension distribution costs. (263-264).

The low-tension system is designed to reflect peak demands on various parts of the low-tension grid. The closer the grid equipment is to the customer, the greater the importance of ICMDs in sizing equipment. Likewise, the further the equipment is from a customer, the greater the importance of class NCPs in designing equipment. Therefore, to reflect the fact that both the NCP and the ICMD are considered in designing the low-tension system, the Company averages these values to allocate the cost of the low-tension grid among customer classes (263).

NYPA's proposal to use only ICMDs to allocate low tension costs should be rejected because it assumes that Con Edison's secondary networks are designed to supply the sum of individual customer loads. For this to be true would require that all customers reach their maximum demand simultaneously and that NCPs would equal ICMDs. However, it is not the case that coincident class loads equal the sum of the maximum demands of customers within a particular class. For example, residential classes have a large difference between NCP and ICMD, and a network serving these customers would not need the capacity to supply the sum of the ICMDs of customers on that network because these customers simply would not all reach their maximum demands simultaneously.

The allocation of low tension costs solely on the basis of ICMDs shifts costs to classes where ICMDs far exceed NCPs (residential customers) and benefits those classes where these two allocation factors are more closely aligned (NYPA and large commercial customers). The NYPA Panel's exclusive use of ICMDs in developing the low tension demand allocator would serve to increase the SC 1 residential deficiency to $79.5 million from the Company's filed $4.2 million. (4670-4671). Conversely, this methodology would decrease NYPA's deficiency to $17.9 million from the filed $30.2 million. (4669).

e) Research and Development Expense

NYPA proposes to reduce its ECOS deficiency to $27.9 million (Exh. 308, page 13 of 15) from the Company's filed $30.2 million by removing any allocations of R&D costs to NYPA. The NYPA Panel states that it funds its own programs and therefore should not share in the Company's cost for R&D, especially since they both pay dues to many of the same organizations, such as EPRI and NYSERDA.

NYPA's proposal to allocate R&D costs only to Con Edison classes should be rejected because the Company's R&D efforts help reduce costs and improve reliability for all customers, including NYPA. (267-268). The fact that NYPA pays dues to the same organizations is irrelevant. NYPA benefits from the Company's contributions to these organizations as do all Con Edison customers. NYPA customers should not get a "free ride" on the Company's expenditures in this area as they will enjoy the same benefits of these efforts even if they made a lower or no contribution.

f) Use of Historic Cost Study – 2005 Costing Disproportionate to Future Investment Which Is More Heavily Weighted Towards Distribution

The NYPA Panel contends that it is inappropriate for the Company to rely on a 2005 ECOS study to establish future rates. They propose to adjust the Company's study to account for the nature of future capital investment, which is more heavily earmarked for distribution (for which NYPA receives a smaller allocation as compared to transmission costs). (4637). NYPA's concern is invalid because the total revenue requirement is not based on incremental investment but on return on total rate base plus total expenses. (268). In addition, the Electric Rate Panel testified that there was no change in the relative relationship between transmission and distribution when looking at historical data beyond the cost study time period. (421).

g) Tolerance Bands

Absent outright dismissal of the Company's filed ECOS study, the NYPA Panel recommends increasing the tolerance band to 20 percent to remedy the "instability" of the study's results. (4627). The NYPA Panel is apparently equating the results of introducing their drastic change in allocation methodology with instability of the Company's ECOS study. Upon cross-examination, the NYPA Panel agreed that their proposed change to use the ICMD measure as the sole allocator for low tension demand costs would increase the SC 1 residential class deficiency from $4.2 million to $79.5 million. (4670-4671). This drastic change in study results stems from NYPA's costing assumptions and not from inherent instability in the Company's filed ECOS study.

Historically, class revenue responsibility has been measured with respect to a 10 percent tolerance band around the total system rate of return. Classes would not be considered "surplus" or "deficient" if the class ECOS rate of return falls within this tolerance band. (178-179). The Company has demonstrated throughout this proceeding that it has employed sound methodologies in developing its ECOS study and has further highlighted the numerous errors NYPA has put forth in their criticism of the study. Therefore, the Company recommends the Commission continue its long standing practice of employing a 10 percent tolerance band.

4. City's Position on the ECOS Study

NYC claims that the ECOS study is flawed (4567) and recommends that the Commission not use it as the basis of interclass revenue allocation in this case. Witness Rosenberg, representing NYC, proposes three revisions (4577-4578) to the Company's filed ECOS study that serve to reduce the NYPA deficiency and thereby arbitrarily shift costs to other Con Edison customers. NYC's proposed revisions are to the following topic areas:

a. Treatment of NYPA as a single class

b. Functionalization of line transformers

c. Weighting of NCP/ICMD

a) <u>Treatment of NYPA as a Single Class</u>

Dr. Rosenberg presents an incorrect calculation of the high tension allocator, which arbitrarily serves to reduce NYPA's deficiency to $15.9 million. (273). In Dr. Rosenberg's analysis, he advantages NYPA by creating a single coincident NYPA load shape and ignores the cost responsibility of the underlying customer groups. He combines internally homogeneous groups (*e.g.*, Traction load and New York Housing Authority) into one heterogeneous NYPA grouping for purposes of determining an NCP allocation factor. NYPA's position destroys the foundation upon which customer classes are determined. Classes evolve over time based on aggregation of customers that exhibit homogeneous usage characteristics. For example, residential customers exhibit similar usage patterns that are unlike the usage characteristics of commercial customers. (271-272).

The creation of a coincident NYPA load shape for high tension allocation purposes tends to dilute the cost responsibility for certain subgroups, such as Traction, where investment in high tension equipment is specifically made to meet the loads of these customers. Traction loads peak during the evening rush-hour, while the NYPA peak occurs during morning hours. A coincident NYPA load would tend to under-allocate high tension costs to this group of customers. (272).

While creating a coincident load shape for only NYPA customers and not for Con Edison classes, Dr. Rosenberg arbitrarily reduces the NYPA deficiency. (273). Using a coincident NYPA demand, which is by definition lower than the sum of the demand responsibilities of

NYPA customer groups, in combination with the Company's non-coincident demands for Con Edison classes, only advantages NYPA.

If a single Con Edison load shape were developed by aggregating all Con Edison classes vs. NYPA vs. EDDS, for high tension allocation purposes, this approach would result in Con Edison and EDDS being average and NYPA being $26.5 million deficient. This $3.7 million reduction from the Company's filed $30.2 million NYPA deficiency is in stark contrast to NYC's proposal, which reduces NYPA's deficiency to $15.9 million due to its inconsistent application of a hypothetical aggregation rule. Dr. Rosenberg seeks to benefit NYPA (and consequently NYC) by arbitrarily maintaining unique Con Edison classes, while presenting NYPA load on a coincident basis. (273-274).

b) <u>Functionalization of Line Transformers</u>

The City contends that the Company erred in its functionalization of low tension distribution line transformers. They propose to categorize underground transformers below 50 KVA and overhead transformers below 7.5 KVA as customer related. NYC points to the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual ("NARUC Manual") to justify assigning a portion of line transformers to the customer component. (4572-4573). NYC's position is incorrect. The NARUC Manual is a general guide to performing cost analyses and as such, needs to be taken in context of the utility's own understanding of its accounts. The Company assigned line transformers to the demand component due to the fact that its system is composed of predominantly large transformers. In its analysis, the Company also determined that small transformers (with sizes up to and including 50 KVA) comprise less than 1 percent of the book cost of the line transformer account, and therefore the entire account was classified as demand related. (275).

It is important to note that the Company and several parties, including NYC, participated in an ECOS collaborative as part of the 2005 Rate Plan that examined how the Company functionalizes low tension distribution costs between demand and customer in its ECOS study. (182-183). While changes were made to certain allocations as a result of the collaborative, no change was made to the Company's longstanding methodology of allocating line transformers entirely to the demand component.

c) <u>Weighting of NCP/ICMD</u>

Dr. Rosenberg's proposal to increase the weighting of ICMDs in the low tension allocation should be rejected. The Company's arguments presented above regarding the NYPA Panel's recommendation to develop a low tension demand allocator based solely on ICMDs are also applicable here. Dr. Rosenberg proposes to increase the ICMD weighting from 50 percent to 60 percent for most customer classes and from 25 percent to 40 percent for the SC 1 and SC 7 residential classes. (4577). He describes this change as giving "slightly more weight to individual customer demands than to integrated non-coincident class demands." (4578). While neither one of these changes is "slight," the change from 25 percent to 40 percent for the SC 1 and SC 7 residential classes is not only dramatic but serves to shift costs away from NYPA at the expense of residential customers. As the Electric Rate Panel indicated, Dr. Rosenberg provides no study to substantiate his suggested weighting. While the Company's 50/50 methodology is not founded in a particular study, it at least recognizes that each variable is of equal importance. (275).

5. <u>Additional Comments on NYC's Review of the ECOS Study</u>

In addition to NYC's three recommended revisions to the ECOS study, NYC criticizes the Company's functionalization of A&G expenses in the ECOS study, stating that the

methodology is not consistent with accepted practice. (4586). NYC presented reference to two methodologies (two-factor approach and three-factor approach) for allocating A&G expenses as stated in the NARUC Manual (Exh. 12). While the Company did not explicitly follow the two methodologies presented by NYC, it did take guidance from NARUC in that a more detailed methodology (based on a combination of labor and O&M expenses) is also appropriate to functionalize these costs. Specifically, the Company performs an analysis of individual PSC Accounts that comprise A&G expenses and determines whether an O&M or labor allocation is appropriate (280), which is similar to the three-factor approach. (354).

Dr. Rosenberg also recommends that a 20 percent tolerance band be used if "the Commission decides to use the filed ECOS as a guide for interclass revenue allocation." (4568). He argues for the expansion of the tolerance band to address what is in his opinion the "unreliable nature of the ECOS." (4566). As explained above, Dr. Rosenberg proposes drastic changes to costing methodologies, which result in dramatic cost shifting away from NYPA. The Company has addressed each of NYC's proposed revisions to the ECOS study and has found them to be invalid. The Company would agree that different methodologies can produce different ECOS results but does not agree to a change to the tolerance band to achieve NYC's proposed results. The Company's current and previous filings are consistent and are not the source of this claimed unreliability. (280).

Absent Commission adoption of his methodologies, Dr. Rosenberg proposes to increase the tolerance band claiming that the Company's ECOS study is flawed. This proposal manipulates the tolerance band to directionally achieve the results of his erroneous cost allocations. As explained by the Electric Rate Panel, the Company uses sound costing principles in developing the ECOS study. To the extent that the Commission finds the Company's ECOS

study to be reasonable, Dr. Rosenberg's recommendation to expand the tolerance band should be rejected.

6. Westchester Position On The ECOS Study

Westchester proposes to allocate transmission costs on the basis of the one-hour peak on the system peak day. The Company disagrees with this recommendation and defended its use of a 20-hour average as a reasonable measure of peak-loading conditions. The Con Edison electrical system is designed to provide for short-time overloading. Repeated high loads over a period cause the failure on the transmission and distribution system, not the short single peak incidence. The four-hour demand over five days recognizes these design features and operation of the system. The underlying principle for using this methodology is cost causation -- costs are incurred to meet demands occurring over a broader time period, not during a single hour's peak demand. This averaging methodology has been well established in previous cases before the Commission and recognizes that transmission costs are incurred to meet system loading conditions over longer periods of time than one hour on one system peak day. (270).

In calculating a new transmission allocator, Westchester held certain classes constant and increased others in proportion to the growth in their respective ECOS transmission allocators between the 2002 and 2005 studies. Using this methodology, which erroneously assumes no growth in NYPA's transmission allocator, results in an unwarranted reduction in transmission costs allocated to NYPA. (282). This calculation incorrectly reduces the NYPA transmission allocator from 13.7 percent to 12.7 percent. (5471). In fact, upon cross-examination, the Electric Rate Panel indicated that a peak day four-hour analysis, which would include the one peak hour estimated by Westchester, would produce a NYPA transmission allocator that was about the same as what was filed in this proceeding. (373-374).

Besides using a one day, one hour allocator for transmission costs, the Westchester Panel arbitrarily used the same allocator to assign high tension costs. High tension distribution costs are generally allocated on the basis of class peaks or NCPs. (283). This costing methodology has been incorporated into numerous cost studies filed before this Commission. Westchester has provided no basis for a change to the current costing methodology. Westchester's proposal to use the same allocator for high tension distribution costs as for transmission costs appears to be simply driven by a desire to shift costs away from NYPA.

The Westchester Panel indicates that there should be a "second cost of service study collaborative to examine alternate methods of allocating demand related plant." (5470). The Company spent significant time and resources dedicated to the last collaborative and parties had ample opportunity to present their allocation proposals at that time. The parties to the collaborative did not present any studies that would warrant a change to the Company's demand allocation methodologies. (283).

7. <u>Conclusion – Costing and Revenue Allocation Proposals</u>

NYPA, NYC and Westchester have all proposed recommendations regarding revisions to the Company's ECOS study. These proposals all serve to benefit NYPA at the expense of Con Edison customer classes. The Company's costing methodologies are proper. The results-oriented proposals without regard to sound costing methodologies and industry practice of other parties should be rejected.

a) <u>Summary of Parties Positions on Revenue Allocation</u>

The Staff Rate Panel agrees with the Company's proposed revenue allocation of the T&D revenue requirement among the classes stating that "[t]his approach recognizes the results of the ECOS and balances the rate increase to all classes." (4889-4890). This approach has been used

by the Company in prior cases and has been accepted by the Commission." (4890). However, Staff suggests an alternate revenue allocation for the Commission to consider if it sees the need to further ameliorate potential bill impacts of the overall rate increase in this case. Staff's alternate revenue allocation would address only 1/3 of the total deficiency exhibited by the ECOS study (as modified using a 15 percent tolerance band). (4893-4894).

NYC recommends that NYPA's deficiency (as modified using a 20 percent tolerance band) be phased in over three years (4591) if the Commission rejects an across-the-board uniform increase to each class. *(id.)*

Westchester suggests that NYPA's deficiency, as determined from the Company's ECOS study, not be eliminated in one year, but rather much more gradually. (5473).

Furthermore, Staff also suggests making a mitigation adjustment so that no class receives an increase greater than 150 percent or less than 50 percent of the system average increase. (4892-4893)

b) <u>Company's Response to Proposals on Gradualism in Revenue Allocation</u>

As explained by the Electric Rate Panel, the Company has already expressed its willingness to gradually phase in the reduction of NYPA's revenue deficiency in the context of a multi-year plan. This approach is reasonable and would moderate the increase to NYPA. (206). However, the Company does not fully concur with Staff's mitigation adjustment which would limit the increase to NYPA at 150% of the system average increase. The Electric Rate Panel explained "Generally, we should keep working towards parity for all classes, *i.e.*, all classes should approximate our overall system rate of return. To the extent that such a proposal would cause us to significantly diverge from achieving this objective, we would be opposed to such a proposal." (299). To remain consistent with prior practice, the Commission should adopt a

higher ceiling applicable for NYPA because of the longstanding NYPA deficiency and because NYPA delivery service represents only about 25 percent of NYPA customers' total bill. For example, in Case No. 91-E-0462[223], the Commission set an annual ceiling on overall increases to NYPA of 175 percent of the system average increase based on NYPA's then revenue deficiency of $33 million. Equally important, in the Company's last electric rate case (Case No. 04-E-0572), the 2005 Rate Plan Order (p. 98) allowed for a NYPA increase of 1.66 times the overall delivery service revenue increase on a cumulative basis over three years with an increase in RY1 that was 1.825 times the overall delivery service revenue increase.

c) Comments to Parties' Complete Dismissal of ECOS Study in Revenue Allocation

As previously mentioned, the Company takes issues with both NYPA's and NYC's proposals to double the tolerance band employed in the ECOS study from 10 to 20 percent in the event that the Commission decides to make use of the 2005 ECOS in allocating the proposed rate increase. The Company also objects to Staff's proposal to increase the tolerance band from 10 to 15 percent for the reasons previously explained. As an alternative to this approach of increasing the tolerance band, NYPA recommends that the "proposed rate increase (or, for that matter, any future increase) should not be based on Con Edison's ECOS study since the results do not follow the most basic cost-causation principles." (4626). Instead, NYPA and NYC propose that any rate increase granted to Con Edison be spread uniformly among NYPA, EDDS and Con Edison classes (4626 and 4590), *i.e.*, each class would receive an equal percent increase. These recommendations completely ignore the fundamentals of rate design, which is that rates should recognize cost causation. The practice of employing ECOS studies in cost and revenue

[223] Case No. 91-E-0462, Appendix G – Agreement and Settlement Concerning Revenue Allocation Issues, dated January 23, 1992, to the Agreement and Settlement Concerning Electric Rates of Consolidated Edison Company of New York, Inc., dated January 24, 1992.

allocation is a sound ratemaking principle and should not be summarily dismissed. The primary purpose of an ECOS study is to match cost causation with cost responsibility. Ignoring the results of the ECOS study in its entirety is capricious and will only serve to perpetuate the longstanding subsidization of NYPA by Con Edison and EDDS customers, including causing some Con Edison classes to subsidize other classes.

The Company strongly believes that all classes should provide a return on investment approximating the overall system average return. As discussed above, various parties have proposed modifications to the ECOS study aimed at reducing NYPA's cost responsibility at the expense of residential customers. On the other hand, the Company has applied consistent unbiased costing procedures not designed to benefit any particular class. The results of the cost study submitted in this case are consistent with the results of the 2002 ECOS study submitted in Case No. 04-E-0572. In that case, the ECOS study showed a deficiency of $43.3 million. Under the 2005 Rate Plan, NYPA was assessed only $10.5 million of the deficiency. The 2005 ECOS study again shows that NYPA continues to underpay and that the revenue deficiency is $30.2 million. Accordingly, the ECOS study results should not be dismissed. It should be utilized as the primary tool in allocating the Company's revenue requirement among service classes so that all classes pay their appropriate share of the costs of providing service.

8. <u>Street Lighting Facilities Charge</u>

Dr. Rosenberg's objection to the proposed increase in the street light facilities charge from its current value of $5.86 to $12.51 per month is invalid. The $12.51 is the result of first increasing the facilities charge from the 2002 cost study level of $5.86 to the 2005 cost-based rate of $9.14 per month. The next step was to increase this cost-based rate by the overall system rate increase. (284).

Dr. Rosenberg and NYC witness Galgano claim that 2005 is an aberration in terms of street lighting expenses because of the abnormally high number of street light repairs made in that year. As explained by the Electric Rate Panel, street light repairs increased by 39 percent from 2002 to 2005. Annual 2006 and 2007-to-date expenses also indicate that the 2005 level of street lighting repairs was not an aberration. (285-286). Additionally, the operations portion of street lighting expenses increased significantly from 2002 to 2005. These costs are expected to continue and must therefore be captured as part of the NYC street light facilities charge. (284).

Dr. Rosenberg also takes issue with the Company's use of a system rate of return in calculating the street lighting facilities charge, as opposed to the use of the return at the lower end of the tolerance band. Upon cross examination, the Electric Rate Panel indicated that street lighting costs were directly assignable and thus not requiring the use of a tolerance band. (394). In addition, an overall system escalation was applied to the cost study result instead of applying the NYPA increase. (393). This use of the overall system rate increase addresses NYC's concern that the cost study calculation was done at the average system return.

B. Proposed Delivery Rate Design

1. Design of Non-Competitive Delivery Charges

a) Rate Design for NYPA Delivery Service and EDDS Customers

Rate design for NYPA delivery service and EDDS proceeded from the basic allocation of the revenue increase. Except as previously discussed with respect to the increase in the street lighting facilities charge, no party had any major objections to the overall rate design for NYPA and EDDS. Specifically, the Company designed rates for NYPA and EDDS in the following manner (222-223):

- The facilities charge applicable to New York City street lights was increased as described above to better reflect the cost of facilities specifically associated with service to street lights.

- All other Rate I and Rate II charges under the PASNY No. 4 delivery service rate schedule were then increased to recover the balance of the NYPA revenue increase. Consistent with the standby rate guidelines, Rate III and IV rates were developed for each class within the NYPA tariff to be revenue neutral at the proposed revenue level, *i.e.*, Rates III and IV were developed to produce the same delivery revenues as the equivalent non-standby rates.[224]

- The current conventional and time-of-day ("TOD") rates under the EDDS rate schedule and SC 15-RA of the P.S.C. No. 2 rate schedule were increased by the base rate percentage increase applicable to EDDS.

b) <u>Rate Design for Con Edison Classes</u>

The rate design process for the Con Edison SCs consisted of the following steps: (1) unbundling of rates for competitive services in accordance with the Commission's Unbundling Policy Statement;[225] (2) determination of the T&D related delivery revenue increase to be applied to non-competitive delivery charges; and (3) design of rates for non-competitive delivery charges. (210).

Under the Company's proposed rate design, the rate year "non-competitive delivery revenue increase" to be applied to non-competitive delivery charges was determined by subtracting the rate-year competitive service revenue requirement for each class from the rate-year T&D related delivery revenue increase allocated to each class. For use in rate design, the rate-year non-competitive delivery revenue increases for each class were then restated on the basis of the twelve months ended December 31, 2005. (216-217).

The basic rate design principles employed by the Company for its non-competitive delivery charges (217-222) were generally uncontested by the parties except for some limited

[224] Case No. 99-E-1470, <u>Opinion and Order Approving Guidelines for the Design of Standby Service Rates</u> (issued October 26, 2001).
[225] Case No. 00-M-0504, Statement of Policy on Unbundling and Order Directing Tariff Filings (issued August 25, 2004).

objections made by CPB, the E-Cubed Company and Joint Supporters, and NYPA. The Staff Rate Panel found the Company's class specific rate design guidelines to be reasonable. (4896).

(i) <u>The Customer Charge Was Properly Calculated.</u>

The Company opposes CPB witness Niazi's position that the Company maintain the SC 1 and SC 7 customer charge at its current rate level or, alternatively, set the charge no higher than the current embedded customer cost. (4803). As explained by the Electric Rate Panel, both of Mr. Niazi's proposals should be rejected because they would result in rates that are below rate year costs.

As shown in the 2005 ECOS study (Exhibit 7, Table 6, page 2), SC 1 and 7 customer costs are $12.20 and $17.37, respectively, as compared to the current SC 1 and 7 customer charge of $11.78. These customer costs are based on 2005 costs and current revenue levels prior to any proposed increase. Under the Company's proposal, the current SC 1 and SC 7 customer charge of $11.78 was increased by the overall base rate increase assigned to SC 1 ($11.78 multiplied by 29.15 percent or $15.21) to bring the customer charge for both classes more in line with costs and revenues in the rate year. (299-300).

(ii) <u>E-Cubed and Joint Supporters Proposal to Amend The Standby Tariff Should be Rejected</u>

The Company takes exception to the proposals made by E-Cubed and Joint Supporters witness Brown, with respect to the Company's standby rate tariffs (SC 14-RA). First, Mr. Brown proposes that the current exemption from standby rates for designated DG facilities be extended through the end of the Company's rate plan, *i.e.*, through March 31, 2011. Second, he opposes the use of "ratchet charges" and "surcharges," which apply to a customer when the customer's contract demand is exceeded, referring to them as "excessive" and "highly costly." Instead, he recommends that there needs to be developed "a means through which the host

facility be held responsible for the performance of their systems, but only at a level appropriate for the time and electric power market costs, etc. during a period when the system fails to deliver as scheduled." (4448). He also suggests that the customer be given one free ride and not be responsible for paying the ratchet charge the first time the customer's maximum monthly demand exceeds the contract demand by more than 10 percent. (300-305).

With respect to Mr. Brown's first proposal on extending the exemptions for standby rates, the Commission has already considered this proposal through its various standby rate orders, which have provided developers of DG designated technologies generous notice that the exemption eligibility period would end on a date certain. The Commission initially established a deadline of May 31, 2006, and later extended the deadline to May 31, 2009, for commencement of operation of the DG designated technologies.[226] Additionally, those customers who do commence operation of their facility after May 31, 2009 but before January 31, 2011 are accorded the benefit of a rate phase-in until February 1, 2011. (300-301).

As for Mr. Brown's second exception on the use of "ratchet charges" and "surcharges," including one free pass, the Electric Rate Panel points to past Commission rulings that already rejected this argument when it approved Con Edison's standby rates. (301). As set forth in the Commission's Order Establishing Electric Standby Rates, issued and effective July 29, 2003, the Commission stated (at p. 11) that the charges "provide an incentive for the customer to manage its load so as to avoid the ratchet provision and to estimate its demand correctly so as to avoid the penalty provision." With respect to computing the contract demand charge, the standby rate guidelines reflected in the Commission's Opinion No. 01-04, Opinion and Order Approving Guidelines for the Design of Standby Service Rates, issued and effective October 26, 2001, in

[226] Case No. 02-E-0781, Order Granting Rehearing in Part and Continuing Standby Rate Exemptions (issued and effective October 25, 2006).

Case No. 99-E-1470, specify (at p. 4) that "Contract (Fixed) Demand Charges should apply to the customer's maximum potential annual metered demand or connected load." As emphasized by these rulings, the Commission-approved ratchet charge is intended to provide a cost-based rate that also provides an incentive for customers to estimate their demand correctly and therefore pay for costs they impose on the system. With respect to the surcharge, current tariff provisions provide customers the option of avoiding any surcharge by merely agreeing to have the Company set the level of the contract demand. Customers who opt to establish their own contract demand incur the surcharge only if they exceed their contract demand by more than ten percent, thereby providing such customers considerable leeway in establishing their contract demand. Moreover, if a customer can demonstrate that electricity consuming equipment is removed or abandoned or that permanent energy efficiency or load limiting equipment has been installed, it may receive a reduction in its contract demand. (300-304).

c) <u>NYPA's Proposed Allocation of DSM Costs Should Be Rejected</u>

Finally, the Company disagrees with NYPA's position that DSM costs be allocated to NYPA using a demand based allocator as opposed to a per kWhr basis. In support of its proposal, NYPA argues that the programs are designed to reduce demand and will thus reduce demand based costs. (4652).

As demonstrated by Company witness Craft, the Company's DSM programs are designed to achieve demand reduction through permanent energy efficiency measures. Customers participating in such selected programs will benefit directly through energy cost reductions. (2990). Therefore, a demand allocator is no more appropriate than one based on kWhs for allocating DSM program costs. In any event, the Commission has traditionally allowed recovery of public policy costs, even those that may be demand-based, on a kWh basis. (305). For

example, the System Benefits Charge and the stranded cost recovery mechanisms of other New York State electric utilities are examples of cases where the Commission has approved recovery of demand-related costs through per kWh charges. (317). Since the DSM programs being proposed by the Company are public policy programs that will provide important environmental benefits through reduced fossil-fuel generation emissions, they are appropriately recovered on a per kWh basis. (2990).

2. Design of Unbundled Competitive Charges

Except for some limited objections by the Staff Rate Panel, no party raised any objections or commented on the design of the Company's unbundled competitive charges. As explained by the Electric Rate Panel, the Company unbundled (a) the electric procurement function into separate Merchant Function Charges ("MFCs") consisting of supply-related components, including purchased power working capital and other procurement costs, and credit and collections/theft components, (b) costs associated with the billing and payment processing function into Billing and Payment Processing ("BPP") Charges, and (c) metering functions into three separate competitive metering charges for meter ownership, meter data service provider and combined meter service provider and meter installation costs. (183-191, 210-216). The Staff Rate Panel found the Company's proposals for unbundling competitive services into unbundled rates reasonable and also noted that "[t]he method recognizes that the unbundled embedded competitive service costs, which are based on 2005 data, should be increased to reflect the rate year revenue requirement." (4895-4896).

Additionally, the Staff Accounting Panel agreed with the Company's proposal to revise the way uncollectible ("UB") expenses related to the Market Supply Charge ("MSC") and Monthly Adjustment Clause ("MAC") are recovered from customers. (3605). No other party

commented or made any adjustments to this proposal. As such, it should be approved. As explained by Mr. Rasmussen, the Company proposed to change its method for recovery of uncollectible expenses. Under this proposal, uncollectible expenses associated with the MSC and the MAC would be unbundled from base rates, and separate rate allowances for the MSC and MAC portions of these expenses would be established and recovered through the MSC or the MAC, as appropriate. (2442-2444). This change will benefit both customers and the Company because the recovery of this expense would be more closely tied to the actual revenues that are billed. (2443). As Mr. Rasmussen explained, to the extent that energy costs increase or decrease,[227] there would be a corresponding change in the amount of uncollectible expense that customers pay. *(id.)* Mr. Rasmussen also noted that if this change is approved, the Company would increase the amounts billed in the MSC applicable to full service customers and in the MAC applicable to full service and transportation customer to recover the uncollectible expenses. (2444) The Company's base rate revenue requirement would be reduced by the uncollectible bills ("UB") expense allowance for the MSC and MAC for RY 1 to reflect the removal of UBs associated with the MSC and MAC in base rates. (290).

As explained by the Electric Rate Panel in its rebuttal testimony, the Company modified its initial proposal on recovery of the UBs associated with the MSC to be consistent with the approach taken in the recent Con Edison gas proceeding (Case No. 06-G-1332). Under this modified proposal, UB expenses related to the MSC would be reflected as a monthly adder to the MFC applicable to full service customers instead of as an adder to the MSC. UBs associated with MAC revenues would be recovered through the MAC. (291).

[227] Energy costs represent almost 50 percent of the total billing and therefore almost half of the uncollectible expenses that must be recovered from customers. (2443).

a) Staff's Proposal on Credit and Collection Costs Should be Accepted

Staff objects to continuation of a bifurcated MFC where the credit and collection component would be paid by all customers billed by Con Edison, *i.e.*, both full service customers purchasing their commodity from Con Edison and retail access customers receiving consolidated billing under the Company's Purchase of Receivables Program ("POR"). The portion of the MFC associated with supply-related costs would be paid only by full service customers. (4899). Instead, Staff proposes that commodity related credit and collection costs attributable to customers receiving consolidated utility billing under the POR program be recovered through the POR discount rate charged to ESCOs as opposed to through an MFC. Under Staff's proposal, POR customers would no longer be charged an MFC. (4900-4903).

The Company is in agreement with Staff's proposal since this would conform the design of the MFC applicable to electric service to the MFC design that was recently adopted by the Commission in Case No. 06-G-1332. (288) Consistent with this revised proposal, the Electric Rate Panel proposed that the Transition Adjustment for Competitive Services would be further modified to provide for a full reconciliation of the actual revenue received from the credit and collections-related component for POR customers included in the discount rate with the amount reflected in the design target for the rate year. (289)

b) Staff's Objection to Company's Application of BPP Charges Should be Rejected

Staff's second objection to the Company's unbundled competitive billing and payment processing ("BPP") charges is to the charges for dual service customers being served under a consolidated billing option. Staff claims that "it is unclear whether Con Edison plans to

correctly bill customers for bill issuance and payment processing ("BIPP")[228] charges." (4904). Staff asserts the Commission has decided that "the customer should only pay a utility for BIPP service when receiving both commodity and delivery from the utility for all commodity services taken." (4904). Thus, according to Staff, the utility must collect the entire BPP cost from an ESCO whether an ESCO serves the customer for all commodity or one of two commodities taken when the customer receives a utility-issued consolidated bill. (4904-4905). The Company's unbundled rate design reflects the allocation of BPP costs between electric and gas service.

In the base design of BPP charges, for a dual service customer purchasing both electric and gas supply from Con Edison and being billed by Con Edison, the Company's 94-cent cost to provide BPP services is allocated equally between the services. The BPP charges (one each for electric and gas service) that are imposed on the full-service customer's bill relate one-half of the costs (47 cents) to electric service and one-half of the costs (47 cents) to gas service. The directly opposite situation is the retail access scenario where a single ESCO provides both commodities and issues an ESCO consolidated bill; in that scenario, the customer would avoid both BPP charges and the ESCO would not be billed for BPP either.

Similarly, if the customer is competitively procuring both services from different ESCOs and both services were billed on a consolidated bill issued by the Company, the customer would avoid the BPP charge on each service and each ESCO would pay a BPP charge associated with billing of the commodity it provided. Under the rates approved in the gas case and proposed here, the customer would avoid 47 cents on its electric service and 47 cents on its gas service; the ESCO providing electric service would pay 47 cents and the ESCO providing gas service

[228] Staff's "BIPP" acronym is equivalent to the Company's "BPP" acronym.

would pay 47 cents. In this manner, the customer would avoid the Company's BPP costs of 94 cents, the ESCOs would share equally the 94-cent BPP costs, and the Company would recover its 94-cent BPP costs and no more. (292-297).

Staff has not opposed the rate design or application of the BPP charges in these scenarios.

There are two scenarios where Staff finds the Company's application of the BPP charges problematic: first, where only one commodity is purchased competitively and billed on a Company-issued consolidated bill, and, second, where both commodities are purchased competitively with one commodity billed on a utility consolidated bill but the other commodity is billed directly to the customer by the ESCO.

Under the Company's rate design, when the dual-service customer is competitively purchasing only electricity (or only gas) that is billed on a consolidated bill, the customer would avoid the 47-cent BPP charge associated with billing of that service. If the Company (as opposed to the ESCO) is issuing the consolidated bill for the competitively-procured service, the customer's ESCO would be billed a 47-cent BPP charge equal to the 47-cent BPP charge the customer avoided. The customer would continue to be billed the 47-cent BPP charge on the service for which Con Edison was continuing to supply commodity and for which Con Edison continued to have a billing obligation.

If the dual-service customer described above competitively obtains supply for the second service but is billed directly by the ESCO for that supply, the BPP charges on the second service would be applied to the customer because the Company would still be obligated to issue a bill for the delivery service for the second commodity. That is, while avoiding the 47-cent BPP charge on the service that was billed under the utility's consolidated bill, the customer would continue to be billed the 47-cent BPP charge on the service for which Con Edison had a

continuing obligation to render a delivery-only bill. Only the ESCO supplying the commodity for the service billed on a consolidated basis would be billed the 47-cent BPP charge.

Staff disagrees with the Company's proposed application of the BPP costs in the two billing scenarios described above. In these scenarios, Staff claims that the Company is required to charge the ESCO supplying the commodity being billed on the utility's consolidated bill a BPP charge equivalent to the Company's total BPP costs (94 cents) and charge the customer nothing. (4904). In support of its position, Staff refers to Commission orders issued on May 18, 2001, and February 18, 2005, in Case No. 00-M-0504, which they claim limits the application of a utility charge for BPP to instances where the customer purchases all commodity services from the utility. (*id.*)[229] Thus, in Staff's view, the Commission concluded that all consolidated billing customers should receive a backout credit, whether consolidated bills are issued by the utility or by the ESCO and whether the customer is purchasing one or both commodities competitively.

The Company disagrees with the Staff's interpretation of those orders. The Commission originally directed the utilities "to develop the backout credits assuming that the utilities exit the retail billing function for all customers or, alternatively, based on the incremental cost of the billing function if it were established today."[230] The assumption underlying the design of the BPP credit, that the utility no longer had any billing function, meant that the backout was not intended to be service-specific on a retail access customer's bill. The Commission's decision to require application or avoidance of unbundled rates on bills of full service customers as well as retail access customers, which are by nature, service-specific, meant that this rationale would no

[229] This purported rule is not applicable in the situation where the dual service customer purchases one commodity from an ESCO that bills the customer directly for that commodity. Because the customer is receiving a dual-service bill from the utility (absent charges for one commodity), the customer must continue to be responsible for BPP charges on each service.

[230] Case 99-M-0631, In the Matter of Customer Billing Arrangements, et al., Order Establishing Uniform Retail Access Billing and Payment Processing Practices (May 18, 2001), pp. 10-11.

longer be applicable to charges to be paid by a full-service customer or avoided by a retail access customer.

Thus, at about the same time as this original directive, the Commission directed the utilities to develop unbundled rates, rather than backout credits, based on service-specific cost-of-service studies.[231] The Commission noted at that time:

> The experience gained through our efforts to set back-out credits for billing and metering functions should illuminate but should not define our inquiry here. Perhaps most importantly, the back-out credits now being examined are closely associated with 'top down' unbundling, in which the cost of a particular utility function is estimated independently of other aspects of the company's business. In contrast, 'bottom-up' unbundling begins with the total costs of the utility's business and then assigns those costs to the various functions, some of which are expected to become competitively available. This proceeding should pursue such a bottom-up unbundling method.[232]

The February 2005 order cited by Staff reflected comments on a Staff-developed bill format model intended for full-service customers only; the model attached to the order was for an electric-only bill and gave no indication that a dual-service bill would not be similarly configured for each service. The statement relied on by Staff, "the billing charge is for a competitive service and is not charged to retail access customers receiving consolidated bills, from either the utility or the ESCO,"[233] could be as readily understood that as to each service taken competitively, the billing charge is not imposed and vice versa. In fact, it is reasonable to assume that no party commenting in that case considered the application of the approved format to dual-service bills.

In this case, the Company proposed an unbundled competitive service rate in lieu of a backout credit, which comports with the Commission's directive to utilities to develop an

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[231] Case 00-M-0504, Unbundling Track, Order Directing Expedited Consideration of Rate Unbundling (March 29, 2001), ("Unbundling Order") Ordering Clause 2.
[232] Unbundling Order, pp. 4-5.
[233] Case No. 00-M-0504, Unbundling Track, Order Directing Submission of Bill Formats (Feb. 18, 2005), p. 23.

embedded-cost-based rate for each competitive service that a customer may avoid by taking that service from an alternative provider. (295-296). Under the Company's proposal all consolidated billing customers, whether consolidated bills are issued by the utility or by an ESCO, will avoid paying the applicable BPP charge. The Commission orders did not specifically address the treatment of combined electric/gas accounts but they clearly state that the rates should be cost-based. The Company's proposed application of the BPP is cost-based because it recognizes that one-half of the costs are reflected in the electric revenue requirement and the other one-half are reflected in the gas revenue requirement on combined electric and gas accounts. (328, 335).

In fact, the Commission acknowledged such a differentiation when it recently adopted the Joint Proposal in Case 06-G-1332 ("2007 Gas Rate Plan"),[234] which sets forth on Table 4 of Appendix D, the gas BPP charges for both single service and dual service gas customers. The Company's proposed electric tariffs are based on this table. Moreover, the Company's proposed treatment is consistent with Staff's proposed treatment of the BPP charge in the situation where there are two ESCOs serving a dual service account under the utility single billing option, *i.e.*, Staff recognizes that the charge should be split between the two ESCOs. (4905).

Additionally, according to a recent tariff filing made by New York State Electric & Gas Corporation, addressing the same issue as presented here by Staff, "NYSEG and Staff, do, however, recognize that there will be two separate BIPP charges applicable to a combination customer receiving gas and electric supply from the Company while a single BIPP charge would apply to a gas-only or electric-only customer."[235]

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[234] Case No. 06-G-1332, Order Adopting In Part The Terms And Conditions Of The Parties' Joint Proposal (issued and effective September 25, 2007) ("2007 Gas Rate Plan Order").
[235] Case 06-G-1386, Letter from New York State Electric and Gas Corporation to Commission Secretary Jaclyn Brilling, dated Aug. 30, 2007, filing revisions to its gas tariff to establish a Bill Issuance Charge.

Pursuant to the 2007 Gas Rate Plan, commencing October 1, 2007, a dual service customer avoids either all or one-half of BPP costs depending on which party issues a consolidated bill and whether one or both services are taken competitively. As stated by the Electric Rate Panel, the whole purpose of unbundling these individual charges is to be able to show customers that these services have specific costs, which may be avoidable. In contrast, under Staff's proposal, even though the Company would continue to render billing for one of the services and incur costs to do that, the customer would avoid all charges for billing. (294-295).

Moreover, Staff's approach is both inherently unfair to ESCOs and creates an adverse incentive to a customer who remains with the utility for one of its services. As to the customer, there would be no further BPP charge to avoid, which would otherwise act as an incentive for a customer to take the other service competitively. As to the ESCO, if a single ESCO were to issue a commodity-only bill for one service and arrange for the utility to issue a consolidated bill for the other commodity, the ESCO would be billed for the full BPP charge even though it would be incurring costs for its own billing activity for the second commodity. (294-295)

The Company's proposed BPP charges as applicable to dual-service customers and the manner in which they will be applied, depending whether the customer is taking one or both services competitively, is rational. The charges are designed so that the Company recovers the BPP costs reflected in its electric revenue requirement. The different BPP charges for customers who take one or both services competitively avoids imposing a burden on ESCOs and inappropriately rewarding dual-service customers who take only a single service competitively. The Staff's objections do not overcome the benefits of the Company's proposed BPP rates, which should be approved.

C. MAC/MSC Changes

The Company proposes two changes to its "MSC" and "MAC" mechanisms.[236] First, the Company is proposing that several supply-related cost components incurred on behalf of full service customers, but currently collected from all customers, be moved from the MAC to the MSC. Second, the Company is proposing that the estimated MAC be simplified to reflect an overall $/kWh charge applicable to all classes and all customers in both NYC and Westchester.

1. The Company Proposes Moving Several Supply-Related Cost Components From The MAC To The MSC

The Company is proposing that the following cost elements be moved from the MAC to the MSC:

> (1) all costs incurred for financial hedging instruments and the net impact of financial hedging instruments, on and after May 1, 2008,
>
> (2) NYISO commodity-related rebills for prior months' costs issued to the Company on or after May 1, 2008;
>
> (3) total costs, rather than only market costs, associated with energy and capacity contracts entered into on or after May 1, 2000 to serve full service customers, except for public policy contracts;
>
> (4) the monthly amortized cost of TCCs purchased on behalf of full service customers through NYISO auctions, direct sales or from the secondary market, on or after May 1, 2008; and
>
> (5) revenues received on and after May 1, 2008 from TCCs held on behalf of full service customers. (0228-0229).

[236] As explained by the Company's Electric Rate Panel, the MSC reimburses the Company for the market value of capacity and energy it procures on behalf of full service customers (in cases where energy and capacity are obtained from a source other than the NYISO, for example, Company owned generation assets, there is an imputed supply cost, based on NYISO market prices; any difference between imputed costs and actual costs is accounted for in the "MAC"). The MAC is paid by all customers, except for NYPA and EDDS classes up to a peak cap kW for each class. The purpose of the MAC is to allow the Company (i) to recover the difference between its total cost of supply and the costs recovered through the MSC, (ii) to collect or credit customers for certain other costs, including production-related costs and NYISO credits related to TCC revenues, and (iii) to recover the costs of certain programs, such as demand side management ("DSM") programs. (227-228).

Recovering these costs from full service customers would better reflect cost causation and is consistent with the Commission's April 19, 2007 Order Requiring Development of Utility-Specific Guidelines for Electric Commodity Supply Portfolios and Instituting a Phase II to Address Longer-Term Issues in Case No. 06-M-0817 ("Hedging Order"). These costs are incurred on behalf of full service customers and should therefore be recovered solely from full service customers. (229). Such recovery is also consistent with the conclusion reached by the Commission in its Order Concerning Petitions for Rehearing and Clarification in Case No. 04-E-0572, issued January 23, 2006, that "it would better reflect cost causation principles if all commodity-related costs and credits would be recovered from or flowed back solely to Con Edison's full service customers, especially where such costs or credits relate to periods of time after retail access was an option for such customers." (229-230).

The Electric Rate Panel distinguished the aforementioned categories of costs from costs associated with Company-owned generation, contracts initiated on behalf of full service customers prior to industry restructuring, or public policy contracts entered into by the Company. (230). The Electric Rate Panel explained that Company-owned generation, contracts entered into prior to industry restructuring and public policy contracts entered into by the Company were all built or entered into on behalf of all customers and should therefore be paid for by all customers. (230). Accordingly, the Company is not proposing any changes to the recovery of these costs. That is, the market costs for purchased power contracts initiated prior to May 1, 2000, Company-owned generation assets and public policy contracts will continue to be reflected in the MSC and the difference between the actual cost and the market costs for these items in the MAC. (230).

In addition, the Company is proposing to modify the MSC tariff provisions to include recovery of all costs related to Regional Greenhouse Gas Initiatives ("RGGI") and other environmental initiatives and to include the recovery of unforeseen commodity related charges. (231). As explained by Company witness Holtman, while these costs cannot be reasonably projected at this time, there is no question that these costs, if and to the extent incurred, will be incurred to serve full service customers. (1238).

Finally, the Company is proposing to modify the MAC tariff provisions to (1) clarify that the cost of Company-owned generation assets includes oil storage and handling costs; (2) indicate that only non-commodity-related rebills issued to the Company will be reflected in the MAC beginning May 1, 2008; (3) reflect proposals made by Company witness Rasmussen and the Accounting Panel to defer on and after April 1, 2008, wholesale Transmission Service Charges ("TSC") revenues received from non-firm transmission contracts and the difference between monthly amortized revenues from sales of the Company's system TCCs and the amount reflected in setting rates; and (4) provide for recovery of unforeseen transmission-related charges. (231).

2. The Company Proposes That The Estimated MAC Reflect An Overall $/kWhr Charge For All Customers In New York City and Westchester.

The Company is proposing to simplify the calculation of the MAC estimates, which consist of a per kW and a per kWhr component for all demand billed classes except SC 14 RA and a per kWh component for all non-demand billed classes. (231-232).

The Electric Rate Panel explained that the MAC currently reflects both per kW and per kWh components that vary by service classification in order to reflect the Commission's determination that the combined MSC and MAC rates for customers in NYC and Westchester

should be equalized.[237;] (232). Since the total cost of supply (MSC and MAC) are no longer equalized,[238] it is no longer necessary to have separate per kW and per kWh MAC estimates or separate rates by SC. Instead, a flat MAC rate per kWh would apply (except for SC 14-RA) commencing May 1, 2008. (232-233). The Electric Rate Panel explained that it was not proposing a per kWh MAC for customers billed under SC 14-RA because the Commission has indicated that stranded production costs should be recovered from standby customers through a uniform mark-up of all delivery service rates.[239] (233). Since the delivery rates in SC 14-RA consist of a customer charge, contract demand charge, and daily as-used demand charges, the MAC rates for standby service customers must be designed to be specifically referable to each of those charges.

Finally, the Company is proposing that the transition from the existing MSC/MAC mechanisms to the proposed MSC/MAC mechanisms be earnings neutral to the Company and that they take effect May 1, 2008 rather than April 1, 2008, *i.e.*, the date the proposed delivery rates would take effect. The Electric Rate Panel explains that the May date coincides with the beginning of the three-month period for which estimated MSC and MAC rates would normally be filed (*i.e.*, for May, June and July), and with the May 1 start of the NYISO summer capability period. (233-234).

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[237] See Case No. 96-E-0897, Order Concerning Retail Access Implementation Plan-Phase 3 (issued and effective February 28, 2000).
[238] See Case No. 00-E-1208, Proceeding on Motion of the Commission in the Matter of Consolidated Edison Company of New York, Inc.'s Plans for Electric Restructuring With Respect to Service Provided in Westchester County, (issued and effective November 25, 2003).
[239] See Case No. 99-E-1470, Opinion and Order Approving Guidelines for the Design of Standby Service Rates, (issued and effective October 26, 2001).

3. Positions Of Other Parties

RESA/Direct and Westchester take issue with certain aspects of the Company's proposed changes to the MSC and the MAC. The Staff Rate Panel proposes additional modifications to the MSC.

a) Staff Proposals To Further Modify The MSC

Staff agrees with the Company's proposal to move the aforementioned categories of supply-related costs from the MAC to the MSC. (4908). Staff proposes two additional changes to the MSC.

First, Staff proposes that the Company file a plan within 60 days of a Commission order in this proceeding to revise its MSC charge to reflect actual day-ahead market prices that were in effect during each customer's billing period; that this plan identify specific issues that will need to be resolved and a proposed schedule of implementation; and that, in the interim, the Company continue to forecast and post the MSC for three months in advance. (314, 4910-4911).

Second, Staff proposes that during the interim period prior to implementation of an MSC reflective of day-ahead market prices, that the MSC estimate continue to reflect the market value of supply and the Adjustment Factor-MSC be modified to include the non-market supply related costs that the Electric Rate Panel proposed to move from the MAC to the MSC. (315, 4908).

As explained by the Electric Rate Panel, the Company is willing to consider an MSC mechanism that takes into account actual day-ahead market prices and generally agrees with Staff's proposal to modify the Adjustment Factor-MSC to include the non-market supply related costs that the Company proposes to move from the MAC to MSC prior to implementation of an MSC reflective of day-ahead market prices. (315). With respect to the latter proposal, the Company proposes that a second Adjustment Factor-MSC component, which would reflect the

recovery of non-market supply related costs being moved from the MAC to the MSC, be established, and that the current Adjustment Factor-MSC continue to reconcile the difference between estimated and actual market costs. (*id.*). The Electric Rate Panel explained that including non-market supply related costs in the Adjustment Factor - MSC would mix the normal reconciliation of the market price estimate with non-market supply related costs. (315-316).

b) <u>Westchester</u>

Westchester generally agrees with the Company's proposal to transfer the recovery of certain costs from the MAC to the MSC, acknowledging that such action is consistent with Commission orders that seek to align the recovery of market-related costs with service to full service customers. (5467). Westchester objects to two aspects of the Company's proposal – the recovery of RGGI costs and costs related to other environmental initiatives through the MSC and the conversion of the MAC charge from one that consists of both energy ("kWh") and demand ("kW") charges to an energy-only charge.

(i) <u>Recovery of RGGI Costs Through The MSC</u>

Westchester opposes the Company's proposal to recover RGGI costs and costs related to other environmental initiatives though the MSC. Westchester states "there is no indication of the types of costs that might be incurred," and that until determinations of cost causation can be made, it is premature to assume that all such costs should be recovered through the MSC. (5468).

As explained by Mr. Holtman, such definition is not required. Such costs will be part of the variable costs of energy production that is used to meet the demand of full-service customers and are therefore properly recovered through the MSC. (1238; 1249).[240]

As further explained by AGC witness Bush (1581), "emissions allowances for certain new environmental programs, including any costs associated with the regional greenhouse gas initiative ... constitute a variable cost that a generating facility incurs to produce energy." Accordingly, he recommends that "Con Edison should be permitted to include environmental costs, including RGGI and any other related costs, in its MSC to the extent that Con Edison demonstrates such costs could not otherwise have been recovered by the Company through the NYISO spot market clearing prices." (1582). Mr. Bush is correct. As explained by Mr. Holtman, to the extent RGGI and other environmental compliance costs are part of the marginal production costs for steam units, they would be included in the offer price. (1248). All revenues received from NYISO for these sales, net of production costs, are flowed through to full-service customers to offset other wholesale energy costs. (1248-1249).

(ii) <u>Conversion Of MAC To Energy-Only Adjustment</u>

Westchester objects to the Company's proposal to convert the recovery of the MAC from a demand and energy charge to an energy-only charge on the grounds that the costs recovered through the MAC are generally demand-related costs and that this change will not be revenue neutral to individual classes of ratepayers.241 (5468-5469). Neither of Westchester's grounds provides a basis for rejecting the Company's proposal.

[240] Assuming these costs will be included in the market price of energy, they would be passed on to retail access customers by their ESCO. (444). In that event, recovering these costs through the MAC (rather than through the MSC) could result in retail access customers paying a disproportionate share of these environmental costs.
[241] Westchester acknowledges that this change will be revenue neutral to the Company. (5467).

First, as to Westchester's argument that the cost components of the MAC are primarily demand-related and, as a general principle of rate design, should therefore be recovered in demand rates, Westchester ignores Commission precedent for the recovery of other demand-related costs through a volumetric charge. (317). For example, the Commission often adopts per kWh charges for the recovery of public policy costs, even if demand-related. Moreover, the recovery proposed by the Company is consistent with the design and application of other charges which include the recovery of demand-related costs, such as the System Benefits Charge[242] and the stranded cost recovery mechanisms of other New York State electric utilities.[243]

Second, Westchester's claim that the change will result in a significant additional cost burden on classes of customers that are billed using an energy only charge (*i.e.*, those classes whose demand cost responsibility is built into their energy rates) is not correct. (5469).

It is not true as Westchester contends that all energy-only classes will experience increases. The Electric Rate Panel explained that the SC 2 class billed under the energy-only MAC rate proposed by the Company would actually have seen a small revenue decrease in 2005 and a revenue decrease of $10 million in 2006. The SC 12 energy-only class would have seen small revenue increases in both years. The SC 7 and the SC 9 maximum rate classes would have experienced decreases in revenues in at least one of the two years studied. (319).

Additionally, as explained by the Electric Rate Panel, if MAC costs were allocated to classes based upon contribution to peak demand as represented by the transmission allocator used in the 2005 ECOS study (as Westchester suggests would be proper), adjusted to exclude NYPA and EDDS customers, 34.9% of total Company MAC costs would be allocated to SC 1 as

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[242] See Case No. 94-E-0952, Re Competitive Opportunities Regarding electric Service, Order Continuing and Expanding the System Benefits Charge for Public Benefits Programs (issued and effective January 26, 2001).
[243] See Central Hudson Gas & Electric Corporation Purchased Power Adjustment Factor (PSC No. 15-Electricity, 6th Revised Leaf No. 106).

compared to the Company proposed methodology, which would have allocated 29.3% of MAC costs to SC 1 for the 12 months ended April 2007. (317). Westchester's approach would have a worse impact on the very customers that Westchester wants to protect. Moreover, the Company's proposal will not result in a significant additional cost burden on customers billed on the Company's energy only rates. As the Electric Rate Panel explained, the effect of converting the demand and energy MAC rate structure into an energy-only rate for a typical Westchester County residential customer using 500 kWh per month would have been an average bill increase of only $0.55 per month for the 24-month period ended April 1, 2007. (318). For a typical New York City residential customer using 300 kWh per month, the proposed change would have resulted in an average bill increase of $0.34 per month for the same period. (318).

Accordingly, the concerns raised by Westchester do not provide a basis for rejecting the Company's proposal to convert the MAC to an energy-only charge.

c) <u>RESA/Direct</u>

RESA/Direct also opposes the Company's proposal to shift the recovery of certain costs from the MAC to the MSC. Specifically, RESA/Direct states that in order to justify recovering the costs related to any financial instrument, contract or TCC through the MSC, the Company must demonstrate that such instruments have been executed solely for the benefit of full service customers. (5151).[244] As explained below, Company witness Holtman fully explained why all of the costs that the Company is proposing to shift from the MAC to the MSC have been executed solely for the benefit of the Company's full service customers.

RESA/Direct witness Smith argues that the Company's proposal has two primary flaws. First, Ms. Smith argues that cost causation principles support moving to the MSC only costs that

[244] RESA/Direct does not oppose shifting from the MAC to the MSC NYISO commodity-related re-bills. (5164).

were incurred solely for full service customers, and that this is not the case for post-2000 purchases, such as Entergy energy costs, or TCCs acquired to hedge full service supply costs. (5151). Second, Ms. Smith argues that the shift proposed by the Company is "likely to inhibit core policy goals adopted by the Commission, and to disrupt existing relationships within the retail market." (5151). As explained below, Ms. Smith is incorrect on both grounds.

First, many of Ms. Smith's remarks are based on a misunderstanding of the current agreement between the Company and Entergy and of the Company's use of TCCs as hedges. Second, Ms. Smith attempts to re-argue portions of the Commission's Order in Case No. 06-M-1017,[245] in which the Company was directed to include in the MSC those wholesale costs incurred solely on behalf of and for the benefit of Con Edison full-service customers.

(i) Recovery of Entergy Contract Costs

Company witness Holtman fully explains why the costs that the Company is proposing to shift from the MAC to the MSC are incurred solely on behalf of the Company's full service customers, and directly addresses the concerns raised by Ms. Smith with respect to the Company's energy purchases from Entergy.

Mr. Holtman testified that the basis for the Company's proposal to shift recovery of Entergy energy costs to the MSC (while continuing to recover Entergy capacity charges through the MAC) must be considered in the context of the Company's historical contractual relationship with Entergy. As Mr. Holtman explained, in 2001, when the Company sold Indian Point Unit 2 to Entergy, Con Edison and Entergy agreed to a power purchase agreement providing the Company with capacity and energy at fixed prices through December 31, 2004; that the

[245] Case No. 06-M-1017, Order Requiring Development of Utility-Specific Guidelines for Electric Commodity Supply Portfolios and Instituting a Phase II to Address Longer-term Issues, dated April 19, 2007 ("Hedging Order").

agreement provided for a "call option" under which the Company and Entergy could negotiate further capacity purchases through 2011; and that these capacity purchases were intended to mitigate the potential market power that Entergy would otherwise possess in New York State. (1243). However, the same is not true for the Company's post-2004 purchases of energy from Entergy.

As Mr. Holtman explained, current and future purchases of energy from Entergy are post-restructuring, short-term arrangements made to serve full-service customers; that the original power purchase agreement associated with divestiture of the plant to Entergy did not provide any mechanism for energy purchases after December 31, 2004; and that unlike the call option for capacity purchases, there was no public policy objective to be satisfied by continuing energy purchases, nor has any such policy objective been identified. (1243-1244).

Mr. Holtman then explained that the energy purchases that the Company has made from Entergy since January 1, 2005, have been made in a series of tranches, executed annually, for terms of three years, as part of the Company's ongoing evaluation as to how to best meet the energy requirements of its full service customers over the near term. (1244). That is, as part of that ongoing effort, the Company determined that the Entergy fixed-price energy would be an effective hedge of its wholesale energy costs, which are incurred solely on behalf of full service customers. These post-2004 purchases have been, and continue to be, discretionary on both Entergy's and the Company's part and therefore in no manner linked to the overall sale of the plant.[246]

Accordingly, Ms. Smith is in error in asserting that the energy purchases from Entergy are from "an old nuclear generation contract that benefited all Con Edison customers." (5153).

[246] Moreover, contrary to RESA's assertion (5161-62), Entergy may contract directly with ESCOs for energy sales.

Also erroneous is Ms. Smith's assertion that it is "highly unlikely that Con Edison signed additional long-term contracts after May 1, 2000 solely to benefit an ever-shrinking class of Con Edison full-service customers…" (5154) or "[i]f it were expected that the Con Edison full-service load would decrease over time, then it would not be appropriate for the Company to sign long-term contracts to exclusively benefit the Con Edison full-service customers to meet an unknown amount of load many years in the future." (5155). As Mr. Holtman explained, the energy purchases are not long term; they are entered into annually, for staggered terms of three years, based upon the forecasted requirements of the Company's full service customers for such periods of time. (1244)

Moreover, Ms. Smith's proposal constitutes a collateral attack on the Hedging Order. That is, Ms. Smith argues that the MSC should be close to the market price. However, in its Order, the Commission dismissed this rationale, rejecting proposals for utilities to cease hedging and instead to flow through spot market prices to their mass market supply customers, stating (5156-5157):

> Taking that step, however, would expose mass market customers to greater price volatility. Under current utility commodity charge mechanisms, the commodity rates billed to mass market customers are monthly average prices. If the source of supply were unhedged market prices, these customers would face the excessive price volatility that they generally wish to avoid and would insure against, even though that volatility would be experienced on a monthly basis.

The Commission goes on to state (Hedging Order, pp. 22-23) that

> Proper cost causation principles require that commodity costs like hedging be recovered through commodity charges imposed on the ratepayers that subscribe to the commodity service. Recovering commodity costs in delivery rates disguises the value of both the commodity and the delivery services and should be avoided. … Therefore, electric utilities shall, in future rate cases, present electric commodity charges that fully recover commodity costs (except for legacy hedges).

And in the Commission's January 23, 2006 order in Case No. 04-E-0572, the Commission states (p. 43):

> …we agree generally that it would better reflect cost causation principles if all commodity-related costs and credits would be recovered from or flowed back solely to Con Edison's full service customers, especially where such costs or credits relate to periods of time after retail access was an option for such customers.

(ii) <u>Recovery of TCC Costs</u>

Ms. Smith also asserts that Con Edison has failed to affirmatively demonstrate that, going forward, the costs associated with financial instruments and TCCs will be incurred to exclusively benefit Con Edison's full-service customers. (5164). That is, Ms. Smith says that with respect to TCCs, "since they are designed to address congestion between an injection point and a delivery point, Con Edison has not demonstrated how they might be acquired to address only default service." (5164). This is incorrect. Mr. Holtman fully explains the TCCs purchased by the Company to protect against fluctuations in the transmission costs or rents realized when moving energy from its point of injection to its point of withdrawal are incurred solely for the benefit of full service customers. That is, Mr. Holtman explains that because the Indeck, Selkirk and Entergy supplies noted on Exhibit 77 all reside outside of Con Edison's service territory, the Company participates in NYISO-sponsored auctions of TCCs, which are sold for 6-month or 1-year terms, in order to hedge the cost of delivering energy from those plants to its system. (1247-1248).

There can be no dispute that the energy purchases and associated financial hedges, including purchases of TCCs, are made solely to serve the needs of the Company's current (and projected near-term) full service customers only. As such, from both a cost causation standpoint,

and consistent with Commission rulings on this matter, these costs should be recovered solely from full service customers through the MSC.

4. The Commission Should Reject CPA's Stranded Cost Proposal.

The Commission should reject the CPA request that the Commission require Con Edison to make a "full accounting of stranded costs," at which point, CPA suggests, the Commission could determine whether it is appropriate to "close out the stranded cost issue." (4810). CPA never describes precisely what "close out" means and fails to provide any justification for its vaguely defined request. In particular, the CPA proposal is based on the incorrect assumption that "at the end of that [multi-year rate plan] period, any residual stranded costs would be small."[247] As noted in Exhibit 77, Con Edison's legacy contracts have terms extending to 2014, 2015, 2016, 2017 and 2036 and the remaining stranded costs resulting from these agreements have been the primary driver of MAC costs. The above market NUG capacity and retained generation assets recovered through the MAC have ranged from $255.4 million in 2003 to $456.4 million in 2006, and could exceed $2 billion before the contracts expire. (1249-1250). Accordingly, given the magnitude, volatility, and longevity of these legacy contract costs, the current mechanism remains the most appropriate method of cost recovery. It has been in effect for more than seven years and CPA does not present any justification for changing it, other than its mistaken assumption that stranded costs would be small by the end of a multi-year rate plan.

D. Hourly Pricing

In his direct testimony, Dr. Rosenberg indicates his support for real time pricing ("RTP")(which is actually day-ahead hourly pricing under the Company's tariff). (4597). He recommends that the Company be directed to convene a working collaborative within 60 days of

[247] Mr. Dowling also refers incorrectly to the "SCS purchase of Indian Point 2." Con Edison sold Indian Point Unit 2 to the Entergy Corporation, who continues to own and operate the unit at this time. (1250).

an order issued in this case to further investigate RTP and to draft a report for submission to the Commission with specific recommendations to ameliorate rate design disincentives to wider participation in RTP. (4601). The Company opposes this recommendation.

Dr. Rosenberg makes a series of general remarks in support of his recommendation. Specifically, Dr. Rosenberg cautions that as between customers that go on the RTP rate and customers that remain on conventional rates, "care must be taken that the MSC / MAC mechanism does not over or under collect from either group of customers." (4600). Dr. Rosenberg then states, "Being on RTP should not mean that a customer is disadvantaged as compared to a customer on a conventional rate design." (4600). Finally, Dr. Rosenberg states, "Given the overall complexity and the potential implications of reconfiguring the elements of the MSC and MAC, great care should be taken to ensure that RTP tariff rates are just and reasonable, and fairly reconciled with conventional rates." (4600).

These general remarks provide no basis whatsoever for convening a collaborative to further examine the Company's RTP rate structure. Dr. Rosenberg does not provide a single example of any aspect of the Company's current rates that disadvantage RTP customers as compared to conventional rate customers. Nor does he provide a single example of how or why the Company's proposal regarding the MAC/MSC may result in such a disadvantage.

Accordingly, the City has not established any basis for the Company, Staff, and other parties expending material time, expense and effort to investigate this issue. For these reasons, the Commission should not adopt Dr. Rosenberg's recommendation.

E. Business Incentive Rate

1. Summary of Company's Current Business Incentive Rate Program

Con Edison's Business Incentive Rate ("BIR"), contained in Rider J to the tariff, discounts delivery charges for eligible electric customers for the purpose of retaining and attracting commercial and industrial customers in order to promote economic development in the service territory. (305). This rate is available to non-governmental customers meeting one of three criteria:

- "Customers receiving a comprehensive package of economic incentives"… "conferred by the local municipality or state authorities" The package of economic incentives may include "substantial tax or similar incentives designed to maintain or increase employment levels in the service area" or a grant of funding from a World Trade Center recovery program to promote business recovery and economic development in lower Manhattan following September 11, 2001.

- "Customers served in new or vacant premises receiving a substantial real property tax incentive or energy rebates under the New York City Energy Cost Savings Program."

- "Not-for-profit institutions occupying newly constructed or converted laboratory space … where such space is solely or predominately used for biomedical research … upon a showing of expected economic development benefits, including new jobs, as a result of the provision of this Rider over the long term and a showing that National Institute of Health grants will not contribute towards the cost of electric service covered by this Rider J."

(306).

In the "Comprehensive Package Program," the BIR is a component of the package of economic benefits, such as relocation benefits, rent abatement, and tax exemptions, that New York City and Westchester may offer to businesses as they compete with neighboring states to attract and retain businesses and encourage expansion of existing businesses. (306). In the "New and Vacant Buildings Program," customers receive the BIR to encourage occupancy in new or vacant premises that qualify for real estate tax rebates or energy rebates provided by New

York City for economic development purposes. (306-307). In the "Biomedical Research Program," not-for-profit institutions ("NFPs") receive the BIR to promote the expansion of the biomedical research industry in New York City and Westchester. (307).

This low cost BIR power is available for allocation in four categories:

- Allocation of 240 MW by New York City in the Comprehensive Package Program
- Allocation of 35 MW by County of Westchester in the Comprehensive Package Program;
- Allocation of 157 MW by Con Edison in the New and Vacant Buildings Program; and
- Allocation of available 20 MW by Con Edison in Biomedical Research program. (3076).

At the present time, 102 MW are allocated or committed and 138 MW are available in the City of New York's Comprehensive Package Program; 22.2 MW are allocated or committed and 12.8 MW are available in the County of Westchester's Comprehensive Package Program; 145 MW are allocated or committed and 12 MW are available in the New and Vacant Buildings Program. Within the New and Vacant Building Program, 19 MW are allocated or committed and 1 MW is available in the Biomedical Research Program. (310-311).

2. <u>Company's Proposed Changes to the BIR.</u>

In its initial testimony, the Electric Rate Panel explained two proposed changes to the BIR. First, the Company proposed to extend the date for accepting applications for one year, from March 31, 2008 to March 31, 2009, in order to support the Company's continued economic development efforts in the service territory. (244). The Electric Rate Panel also noted that in the context of a multi-year plan, the extension would be coincident with the end of the multi-year rate plan period. (245). This suggestion was unopposed.

Second, the Company proposed that customers eligible for BIR under either the New York City Comprehensive Program or the New and Vacant Program in buildings located within 250 feet of a steam main in Manhattan would receive a reduction in their delivery service kW and kWhr eligible for BIR bill reductions during the summer months of June to September if they have electric and/or hybrid electric chillers. (244-245). This electric chiller reduction will be determined by the Company based on the name plate rating of the chilling equipment and the equipment efficiency information supplied by the customer. (245). For each of these summer months, the electric chiller reduction will be deducted from the customer's BIR allocation to determine the load eligible for BIR bill reductions. (245-246).

The purpose of this change is to remove the disincentive for customers to use steam for cooling. (246). This reduction is consistent with prior Commission orders.[248] (246-247). The Company will grandfather existing BIR customers using this equipment within 250 feet of a steam main but any new customers commencing service on and after April 1, 2008 would receive this electric chiller reduction. (436-437). The Company's rate case filing provided facilities expected to come on line after the effective date of the new rate plan, *i.e.*, April 1, 2008, eleven months advance notice of this proposed change. (437). No party has submitted testimony opposing this change. Based on the lack of opposition in testimony, these changes should be approved.

3. CPA Proposed Changes to BIR

CPA witness Luthin proposed that the BIR for Biomedical Research be increased from the existing 20 MW to 77 MW. (4826-4856). Ms. Luthin notes the positive economic and social

[248] See Case No. 04-E-0572, Order on Demand Management Action Plan (March 16, 2006), p. 40, and Case No. 03-S-1672, Order on Consolidated Edison Company of New York, Inc. – Steam Business Development Plan (December 5, 2005).

impact of not-for-profit ("NFP") health and educational institutions in New York City, the stressed economic situation of these institutions, and the effect of increasing energy costs on these institutions. Ms. Luthin alleges that there is a "critical" need for large non-profit hospitals and universities located in New York City to receive low cost power as an economic incentive. (4834). Ms. Luthin further asserts that biomedical research facilities are a sub-sector of New York City's NFP health and educational institutions that are significant contributors to the economic growth of this region. (4826). Citing Memorial Sloan Kettering Cancer Center ("MSKCC") as an example, Ms. Luthin states that NFP biomedical research institutions in Con Edison's service area must construct and maintain state-of-the-art laboratory and research facilities in order to expand research programs, attract the best biomedical researchers, and create new professional staff jobs. (4841-4844). Ms. Luthin cites a study indicating that "New York bio-technology facilities have the highest, by a wide margin, ratio of electric costs as a percentage of total operating costs exclusive of salaries." (4829).

Ms. Luthin recommends that the amount of BIR power available in the Biomedical Research Program should be based on the number of jobs in the entire NFP health and education sector. She develops a ratio representing the amount of power available under the BIR program relative to the total number of jobs in the non-agricultural sector vs. the non-profit, health and education sectors. (4835-4836). Ms. Luthin subsequently submitted for the record various documents she claims supports her position. (Exh. 318-322).

a) <u>History of Biomedical Research BIR Allocation</u>

The October 2, 2000 Settlement Agreement approved by the Commission in Case No. 00-M-0095 provided for the reservation of 8 MW from the New and Vacant Building Program for allocation to "not-for-profit institutions, or affiliates of not-for-profit institutions, occupying

newly constructed or converted laboratory space contained within newly-constructed buildings, additions to or renovations in existing buildings, or buildings newly converted to laboratory space, that is solely or predominantly used for Biomedical Research and/or occupied by Biotechnology companies." (308). Con Edison's tariff was amended effective April 1, 2001 to establish the Biomedical Research Program, and 8 MW became available for this program. (309).

The 2005 Rate Plan increased the amount of power available for allocation through the BIR program by an additional 12 MW, which was reserved for not-for-profit institutions utilizing laboratory space for biomedical research under the existing criteria for such allocations. *(id.*) This increased the total BIR MWs available in the Biomedical Research Program to 20 MW. *(id.*) The 12 MW was phased-in as follows: 5 MW effective as of April 1, 2005, 2 MW effective as of April 1, 2006, and 5 MW effective as of April 1, 2007. *(id.*) Con Edison's tariff was amended effective April 1, 2005 to effect these changes to the BIR Program. (*id.*)

4. <u>Con Edison's Position on CPA's Proposal</u>

Under cross-examination, the Electric Rate Panel succinctly explained the Company's position regarding Ms. Luthin's request – there is no support for it and the Company does not believe that additional MWs are necessary to entice biomedical facilities to move to New York:

> ….none of the data provided really supports whether there should be a separate set aside for biomedical facilities, that they are any different from any other customer competing or that we are trying to attract into our territory ….
>
> …we think the existing allocations under our existing programs should be sufficient based upon what the expectations are for biomedical facilities coming on in the future…. (434-435).

BIR power is provided on the basis of the need to accommodate new, expanded, or retained load. Thus, the availability of BIR power should be based on the amount of power

required to accommodate eligible load. Ms. Luthin has not provided any data that would demonstrate the need for increasing the allocation for the Biomedical Research Program, by a factor of almost four times the existing allocation, for new load that may be eligible under current program criteria. (312).

The material Ms. Luthin provided for the record are insufficient to support her claim. For example, Exhibit 321 is a 2005 study by the Boyd Company purporting to show an operating cost analysis for biomedical facilities. The study contains no data about operating costs for these facilities in New York City; rather it looks at cities such as Rochester and Buffalo, New York; Fairfield County and New Haven, Connecticut, and Princeton, New Jersey. (Exh. 321). Exhibit 318 purportedly shows costs for New York City and four other states. The document notes that the New York City data comes from a survey of six "preeminent biomedical research institutions" with no additional detail as to the names of those institutions, the nature or amounts of the costs incurred by each institution or any other information about the number of facilities or employees involved. Nor does Exhibit 318 explain where the other states' information came from. More importantly, if the "state" information was derived from Exhibit 321, it is questionable merely because Exhibit 321 develops costs by cities or areas, not states.

The remaining three exhibits do not include any additional support for Ms. Luthin's position. Exhibit 319 is a list of potential planned expansions of seven facilities, which does not list any information about these facilities, including, but not limited to, the developing entity, the nature of the proposed development or associated costs, and the projected electric usage. Exhibit 320 is apparently a compilation of CPA member usage with no supporting data. Finally, Exhibit 322 is a document entitled "Operating Costs Biomedical Research," which also does not include any supporting documentation or information for the values noted therein. Accordingly,

nowhere in the testimony or exhibits provided by Ms. Luthin is there any evidence that an additional 57 MWs of electric usage for biomedical research facilities will come on line any time in the future. (432-433).

And even if Ms. Luthin could show that an additional 57 MW will come on line during the term of the rate plan, no demonstration has been made that bio-medical facilities require the BIR rate incentive to stay in or move into Con Edison's service territory. If an incentive for any of these facilities is warranted, there are sufficient allocations remaining under the Company's existing BIR programs for which bio-medical facilities can apply for rate incentives along with other customers. (313, 434). Specifically, bio-medical facilities could qualify for low-cost power under the BIR as a New or Vacant Building Program if they receive energy rebates under the New York City Energy Cost Savings Program or under the Comprehensive Package Program if they receive a comprehensive package of incentives that customer negotiates with New York City or Westchester County. In fact, recently a bio-medical project received an allocation from the City of New York. (313).

As discussed above, Ms. Luthin's 77 MW proposal is seemingly based on changing the criteria for qualifying for the BIR program, from economic development criteria to criteria based upon the number of jobs in the overall health and education economic sector. As explained above, BIR power availability should continue to be based on the amount needed to accommodate new, expanded, or retained load, that is, for projects where the customer is considering leaving the service territory or to entice a new customer to come into the service area or to entice a new or existing customer to expand electric use within the service area.

There has been no demonstration that the 57 MW of biomedical BIR is necessary or warranted. As such, this suggestion should be rejected.

If the Commission nonetheless decides to adjust the allocation of BIR and also adopts an RDM mechanism other than the RARIM as proposed by the Company, the Company could be in the situation of incurring additional costs for this new load without the offsetting benefit of additional revenues, absent, for example, an appropriate adjustment to the sales forecast. (314). Accordingly, adoption of Ms. Luthin's proposal in whole or in part must be evaluated in the context of the implementation of revenue decoupling and appropriate adjustments made to keep the Company whole in this regard.

F. Other Tariff Changes

Company witness Trongone also submitted unopposed testimony which updated the charges for special services and proposed a change to Special Provision D of the SC 4 and 9 tariffs. (153-160).

1. Special Services Fees

Special services are services that the Company is not otherwise required to perform but that the Company agrees to render to a specific customer. The Company charges for these services since the customer population as a whole should not be required to pay for the activities needed by one customer. For example, when the customer is required to perform a high potential proof test and the customer does not have a contractor available to complete this essential work on a timely basis, at the customer's request, the Company would perform this work and charge the customer for this service. (155).

The charges for these services are fixed. The basis for the charges is the Company's cost to perform the service (inclusive of corporate overheads and gross receipts taxes). *(id.)* The charges are determined by reference to the list of cost components in the tariff and the average time necessary to perform the work. *(id.)*

In this proceeding, the Company proposed to update the charges for:

- high potential proof tests based on updated costs for labor and vehicles for a minimum four hour premises visit. The cost would increase from $910 to $1,003 a visit (for up to four hours) and from $230 to $251 for each additional hour. (155-156);

- dielectric fluid tests based on updated labor and vehicle costs. The cost would increase from $525 to $662 for the first sample taken and from $350 to $466 for each additional sample taken. (156);

- Megger tests based on updated labor and vehicle costs. The cost would increase from $230 to $251 per visit *(id.*); and

- Re-inspection fees based on updated labor costs. The cost would increase from $109 to $113 for each re-inspection necessitated when a contractor schedules a final inspection and upon inspection, the Company determines that the required work is incomplete or not in accordance with Company specifications.[249]

(155-156).

No party either commented on or opposed these updated special services fees. As such, they should be approved.

2. <u>SC 4(D) and 9(D) Tariff Change</u>

Mr. Trongone also proposed to modify the availability of the non-residential heating rate discount provided to non-residential customers under SC 4 and 9 who rely entirely on electricity for heating their premises.[250] (158). His proposed modification would grandfather existing customers who receive service under Special Provision D of those service classifications so long as they continue to rely on electricity for all their heating requirements, but new, additional or successor customers would not be permitted to take service under this Special Provision on or after April 1, 2008. *(id.)*

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[249] Mr. Trongone explained that the Company had not estimated the revenues from this re-inspection fee as it is difficult to estimate revenues when the purpose of the fee is to alter behavior. More importantly, he noted that the actual revenues would be *de minimis*.

[250] In his initial testimony, Mr. Trongone noted that there were about 500 customers on Special Provision D. The Company has performed surveys of these customers and currently, about 300 customers remain on the rate.

Mr. Trongone explained that Special Provision D was established in 1970 to promote higher winter demand on the Company's electric system. *(id.)* In reviewing the rates, the Company has recently reconsidered the rationale for promoting off-peak demand because it diminishes the Company's flexibility to perform routine maintenance and replacement work on the distribution system in order to meet peak summer demand requirements. (158-159). More importantly, the majority of the customers benefiting from this discount were not induced to use electric space heating because of the existence of the rate but rather for convenience and financial considerations. (159).

Using electric space heating allows customers to have better control over the areas being heated and as a result, they can save on their heating costs. In rental buildings for commercial space, landlords use electric heating because the amount of space needed for electric distribution units is much less as compared to a central heating plant. It also allows a landlord to shift heating expenses to individual tenants thereby reducing the landlord's overall building costs. *(id.*)

The Company proposal would grandfather the remaining existing customers so long as they continue to meet the requirements of Special Provision D, which may mean providing proof that they still use solely electric heat. New or successor customers applying for service on or after April 1, 2008 would not be eligible for service under Special Provision D. Moreover, the discount rate for existing customers could be re-determined through a new heat impact survey. (160).

No party submitted testimony on this proposed change nor were there any issues raised in the hearings. As such, the proposed tariff change should be approved.

3. Miscellaneous Tariff Changes

The Company proposed other miscellaneous tariff changes which included:

- tariff changes to recognize the unbundling of competitive services (including revisions to the Transition Adjustment for Competitive Services);
- modifications to MAC provisions to continue recovery of the Company's costs associated with Demand Management Programs (including marketing costs and incentives) and recovery of net revenue shortfalls resulting from laws that would permit NYPA to serve non-governmental customers in the Company's service area;
- modifications to MAC/MSC tariff provisions to implement the changes previously described related to transferring recovery of several supply-related cost components from the MAC to the MSC; and
- deletion of obsolete tariff language, including other clarifying tariff changes.

No party raised any objections to these specific tariff changes, and theyshould therefore be adopted by the Commission.

XI. REVENUE DECOUPLING

On April 20, 2007, the Commission issued its Order Requiring Proposals For Revenue Decoupling Mechanisms in Case Nos. 03-E-0640 and 06-G-0746 ("RDM Order"). In compliance with the RDM Order, the Company included in its rate filing its proposal to implement a Revenue Accounting and Rate Incentive Mechanism ("RARIM"). Company witness Rasmussen explained in his direct testimony the principles, goals and benefits of the RARIM (2445-2548), consistent with and in furtherance of the RDM Order. That is, Mr. Rasmussen explained that the Company's proposed mechanism would decouple the impact of sales and revenue growth and thereby remove a potential disincentive that the Company might otherwise have to promoting increased energy efficiency through demand reduction programs, conservation efforts and the wise use of energy. (2445). At the same time, the Company's

RARIM would preserve the Company's interest and incentive to continue to promote economic development and the environmentally sound use of electricity. (*id.*)

A. The RARIM Is The Only Revenue Decoupling Mechanism Ripe For Consideration In This Proceeding

The RARIM is the only revenue decoupling mechanism ("RDM") that may be considered for implementation on April 1, 2008. While various parties have criticized the Company's RARIM and proposed modifications, no other party has proposed an alternative mechanism. While the Staff RDM Panel recommends that total delivery revenues be trued up on a class-specific basis (3972), they provide no details whatsoever as to their proposed mechanism. For example, the delivery revenue forecast by service class that would be the allowed revenues under Staff's proposal has not been provided.

1. The Company's Submittal

Putting the Company's proposal in context is important. In his direct testimony, Mr. Rasmussen set forth the principles of the Company's approach to revenue decoupling and general descriptions of its proposed revenue per customer ("RPC") mechanism and other features, including the manner in which the Company planned to reconcile actual and forecasted revenues. Recognizing that additional detail was required regarding the mechanics for implementing these principles, Mr. Rasmussen stated the Company's intention to provide additional information as to the implementation of the RARIM during the update phase of the proceeding. Additional time was needed because there was inadequate time between issuance of the RDM Order and the Company's filing to develop procedures for implementing the RARIM and providing pro forma calculations. (2449-2450).

At the June 18, 2007 pre-hearing conference, several parties argued that the Company's initial filing lacked sufficient detail as respects its proposed RDM for the matter to be addressed

in their direct testimonies and therefore the update phase of this proceeding would be too late for the Company to first set forth such details, as it would not provide parties an adequate opportunity to evaluate and respond to that mechanism. As a result of these discussions, Mr. Rasmussen submitted Supplemental Testimony on July 13, 2007, on the RARIM, including procedures for implementation, RPC factors by rate class, and a detailed methodology for normalizing electric sales. (2236-2250; Exhs. 160 and 161).

Consistent with the positions of the parties as to the Company's presentation on revenue decoupling in its direct testimony, the Commission must conclude that no other party to this proceeding sponsored an RDM in its direct case. At best, they spoke to generally accepted frameworks for revenue decoupling or discussed criticisms of and/or proposed modifications to certain aspects of the Company's proposed mechanism.

Accordingly, the RARIM remains the only mechanism capable of implementation on April 1, 2008. Implementation of any other mechanism would need to be deferred to a date sometime after implementation of new electric rates on April 1, 2008, since further processes that provide all parties, including the Company, a fair opportunity to evaluate such alternatives through reasonable procedures (whether a collaborative or a hearing), including an opportunity for discovery, would be required.

Some parties to this proceeding propose that consideration and implementation of revenue decoupling be the subject of a separate phase of this proceeding. As discussed infra, the Company would not object to delaying implementation of revenue decoupling, provided, however, if energy efficiency were effectuated other than in conjunction with revenue decoupling, a lost revenue recovery mechanism would be necessary and appropriate.

B. Principles of Revenue Decoupling

Mr. Rasmussen explains that the RARIM should be viewed in conjunction with the Company's proposed energy efficiency program and implemented in a manner that provides appropriate recognition to the importance of maintaining reliable service and promoting economic development in the Company's service territory. (2237). That is, from the standpoint of energy efficiency, the RARIM is designed to eliminate a potential disincentive to promote energy efficiency but does not, in and of itself, provide the Company with an incentive to promote or advance energy efficiency. (2237-2238). As discussed by Company witnesses Craft and Zielinski, positive incentives are critical to an effective and successful revenue decoupling/energy efficiency paradigm. (2238).[251]

Mr. Rasmussen further explains that given the adverse impact on the Company of increases in the per unit cost of service due to the lower growth resulting from successful energy efficiency programs, whether implemented by the Company, NYSERDA and/or other third party providers, it would be contrary to the Company's economic interest to promote energy efficiency

[251] Mr. Zielinski explains that:

> a standard RDM basically seeks to equate utility revenues with the cost of service, including an equity capital return equal to the cost of capital determined by the regulator, on an annual basis. Those who support standard formulations of RDM generally contend that electric utilities have no incentive to promote less use of their service because conservation results in less revenue. They propose, therefore, to decouple utility revenue increases from electricity usage increases through a mechanism that would assure that the utility would earn its regulator-determined cost of service, no more and no less. Thus, a standard RDM, like negative regulation, would effectively limit utility rates of return to achieve the proponent's concept of equity: it seems fair to the proponent to guarantee that a utility will earn its regulator-determined return on equity investment every year, while also limiting a utility to that return. However, using a standard RDM to achieve this conception of equity conflicts directly with the goal of efficiency. When revenues are automatically equated to costs by a standard RDM, including a return on equity investment determined by regulation, the utility has no incentive to improve efficiency because it cannot increase the return to its equity shareholders by doing so. Proponents of standard RDM generally fail to recognize that in restructured electricity markets like New York they are seeking to command distribution companies to act against the interests of their shareholders in order to improve efficiency at the production level of the market in which distributors have no financial interest. An avoided cost in the production market is not an avoided cost in the distribution market. Positive incentives in the interest of shareholders are required to induce distributors to take such actions in the interests of consumers in the production market. (2718-2719).

aggressively absent such incentives. (2238-2239). In addition, an RDM should not eliminate the Company's incentive to promote economic development on its system, which could result if an RDM denies the Company the revenues necessary to maintain its system in a constant state of readiness to meet current and future demands for service. (2240).

Some of the parties to this proceeding recognize these important principles and objectives. Unfortunately, others do not.

Contrary to the dictates of the RDM Order, the Staff RDM Panel takes an unnecessarily restrictive view of an RDM to be implemented by the Company. For example, Staff takes the position that the goal of encouraging economic expansion in the Company's service territory should not be "intertwined with a mechanism designed essentially to true-up forecasted and actual delivery service revenues." (3962). The Commission's view is in stark contrast to Staff's position. For example, the RDM Order directs that the impact of economic development be considered when designing a revenue decoupling mechanism, stating as follows:

> There are a number of design and implementation issues that would need to be considered in the development of an effective revenue decoupling mechanism. These include: whether the mechanism is applied to all or only some customer classes; whether allowed revenues are calculated on a per customer basis (*i.e.*, <u>encourage economic development by allowing utilities to collect revenues for new customers</u>).[252] (emphasis added)

Staff's apparent bias against a revenue decoupling mechanism that encourages economic development must be rejected. The Commission has directed the parties to consider encouraging economic development as an objective of an RDM in this proceeding. The Company has presented such a mechanism, which must be judged on its merits. Moreover, it bears mention that while Staff suggests that "other programs, specifically designed for targeted results, could be used to further the goals of … economic development," Staff makes no such proposals. (3962).

[252] RDM Order, p. 8.

Staff's only comment regarding economic customer growth and retention is that the Company's proposal would exclude all contract and negotiated rate customers and that "these are the type of customers for which Con Edison can exert its most potent and direct influence – the price of the product – to either retain or attract customers" (3974-3975); and the need to apply the RPC mechanism to the remaining customer classes is greatly reduced.

Staff's reasoning is flawed. First, the Company's tariff provides a limited opportunity to offer contracted or negotiated rates to customers under the SC 14 tariff only. (2279). This tariff rate is for standby service and is only offered to customers with on-site generation. (*id.*). In addition, if an existing customer transferred to SC 14, there is no guarantee that the delivery revenue generated under that tariff would be greater than or at least equal to the delivery revenue derived under their prior service class (in the case of an RPC mechanism, the average revenue of their service class), and in fact, the Company may end up worse off with a loss of delivery revenue. (*id.*). Accordingly, the overall Staff position in this proceeding effectively abandons an opportunity to encourage economic development in the Company's service territory by eliminating the Company's existing and historical incentive to promote economic development and providing no substitute incentive.[253]

NYPA claims that promoting economic development operates at cross purposes with the "avowed intention of a decoupling mechanism." (4654). In this regard, NYPA, like Staff, fails to distinguish between the importance of designing an RDM that does not interfere with ongoing Commission policy objectives to promote economic development and energy sales that promote environmental goals, and attempting to capture in a decoupling mechanism decreases in

[253] As to programs designed to encourage excellent customer service, Staff proposes negative revenue adjustment mechanisms, which are addressed in elsewhere in this Brief.

customers' use of energy that may be driven by economic downturn as opposed to energy efficiency measures.

Economic development is not contrary to the intention of a decoupling mechanism. (2258). As CPB witness Elfner states, a "well designed RDM should also not jeopardize other policy objectives, such as a strong economy." (4704). Additional customers contribute to a growing healthy economy, adding to the area's tax base, enabling the government to provide additional and/or improved services, and leading the service area to remain or even become more attractive to existing or new customers. (2258). Accordingly, an RDM should be designed not only to avoid discouraging economic development, but also to encourage economic development. *(id.)* This is analogous to the need for robust energy efficiency incentives, since revenue decoupling may reduce or eliminate a disincentive to energy efficiency but does not provide a utility any incentive to promote energy efficiency. *(id.)* As discussed infra, Staff's revenue adjustment concept, under which actual revenues are trued-up to the level of forecasted delivery revenues, suffers this deficiency. (2258-2259). On the other hand, a properly structured RPC mechanism promotes both energy efficiency and economic development. (2259).

Moreover, two points bear mention regarding NYPA's concerns that the Company would have the incentive to promote unlimited use of energy by new customers and that the Company would be insulated from economic downturn (4655). First, the Company's RPC mechanism would not encourage the Company to promote the unlimited use of energy by new customers since the Company only would be allowed to retain the average revenue per customer, regardless of the amount of energy consumed by each new customer. (2259). Second, NYPA is incorrect that the Company's proposed RPC mechanism insulates the Company from economic downturn, as the Company would suffer a revenue loss to the extent an economic downturn resulted in the

Company's having fewer customers than forecasted. In this regard, it bears emphasis that the sales forecast includes projected economic development. Therefore, under the RPC mechanism, the Company only would stand to gain from the addition of new customers to the extent that they exceeded the projection for new customers in the forecast.

The type of RDM discussed by Staff not only would fail to encourage the Company to continue to promote economic development, it could serve to discourage such development. (2259). That is because the Company incurs additional expenses when it adds new customers to its system. A mechanism that trued-up actual revenues to forecasted revenues for all customers would deny the Company the additional revenues from new customers needed to offset these expenses. *(id.)* Accordingly, there would be a disincentive for the Company to promote economic development. *(id.)*

In marked contrast to Staff's and NYPA's positions, CPB supports a mechanism that is designed to further the goal of economic development. (4704). CPB witness Elfner agreed with the Company that "[u]tilities should continue to have an incentive to encourage and facilitate economic development by increasing the number of customers beyond forecast levels." *(id.)*

1. <u>Environmentally Sound Programs</u>

The Staff RDM Panel rejects the Company's proposal to retain revenues from new environmentally sound programs without providing any basis for its position. (3975). NYPA expresses similar opposition, consistent with their position as to revenues from economic development (*i.e.*, the Company should not be allowed to retain revenues due to load growth, yet be insulated from losses associated with reductions in usage). (4655).

The Company is only proposing to retain 100 percent of the revenues associated with environmentally sound programs, not all load growth on its system. (2260). As indicated above,

one purpose of revenue decoupling is to eliminate a potential disincentive to the utility in promoting energy efficiency. *(id.)* Environmentally sound programs, by definition, promote energy efficiency and are therefore, the types of programs that the Commission should incentivize the Company to pursue. (2260-2261). In addition, we note that the Staff proposal in the energy portfolio standard proceeding to achieve a 15 percent reduction in electricity consumption by 2015 provides that "the EPS planning framework should include a mechanism to account for technologies that could increase electricity or natural gas usage but would be beneficial from a total resource cost and/or an environmental standpoint."[254] Similar reasoning should apply to an RDM. Both the Company (2445) and Staff (Staff Preliminary Proposal, p. 15) identify plug-in electric vehicles as an example of an environmentally beneficial use.

Neither Staff's nor NYPA's approach to revenue decoupling would provide an incentive to pursue such programs. Under Staff's proposal, where actual delivery revenues are trued-up to the forecasted level of delivery revenues, the Company would refund 100 percent of any revenues associated with environmentally sound programs. (2261). In that circumstance, the Company would not only have no incentive to communicate and/or market such programs to its customers, it would have a disincentive to engage in such activities to avoid increasing its expenses without off-setting revenues. (2261-2262).

C. <u>The Revenue-Per-Customer Mechanism</u>

Several parties criticize certain aspects of the RPC component of the RARIM. For the reasons hereinafter provided, these criticisms should be rejected.

[254] Case No. 07-M-0548, Proceeding on the Motion of the Commission Regarding an Energy Portfolio Standard, <u>New York State Department of Public Service Staff Initial Proposal for Energy Efficiency Program Design and Delivery</u> (issued August 28, 2007), p. 15 ("Staff Preliminary Proposal").

1. **The Weather Adjustment Is Necessary and Appropriate**

The Company's revenue decoupling proposal compares actual weather normalized delivery revenues to the "allowed delivery revenues" on a service class basis. (2242-2243). As a result, the Company would be at risk for weather variations from normal weather. As further explained below, this would retain the status quo for the Company's electric service, where the Company is currently at risk for weather variations. No party to this proceeding has established the need to alter this risk for Con Edison in order to implement the Commission's revenue decoupling policies.

NRDC/Pace supports the Company's position that "[a]ctual revenues can be weather normalized before being compared to allowed revenues as long as the weather normalization does not require overly complex calculations." (5320). CPB also supports the Company's position but has no opinion on the proposed methodology for normalizing delivery revenues. (4703). On the other hand, Staff and NYPA are in favor of using actual delivery revenues as opposed to actual weather normalized delivery revenues as the basis for the comparison.

The following areas of concern were identified in relation to the Company's weather proposal:

a. a revenue decoupling mechanism should not be designed to segregate out a factor over which the Company has no control. (3966).

b. there is an incentive to "game" the sales forecast. (3966-3967).

c. the Company's proposal requires close on-going regulatory oversight auditing efforts that would incur unnecessary costs for both the Company and Staff. (3967).

d. the Company's assumption for normal weather is inconsistent with the 30-year average of actual number of cooling degree days. (3968).

e. the Company's proposed mechanism is overly complicated. (3967; 4962; 5321).

f. the regression method proposed by the Company may give a biased estimate for the weather impact if the model is not properly specified. (3968).

g. the average rate used in pricing the weather impact would include customer charges. (4967).

As explained below, these concerns are not well-founded and do not provide a sufficient basis for the Commission to reject the Company's proposal.

a) <u>There Is No Basis For Rejecting A Weather Adjustment Because Weather Is A Factor Outside The Company's Control</u>

Staff's overall perspective as to why excluding weather-related sales fluctuations would not be appropriate for consideration in designing an RDM for Con Edison is that a decoupling mechanism should not be designed to segregate out a factor over which the Company has no control. (3966). Staff's position constitutes a collateral attack on the Commission's RDM Order. Specifically, the Commission lists "whether to include or exclude weather related sales fluctuations" as a design and implementation issue to be considered in developing an RDM mechanism.[255] Staff has provided no basis for excluding weather-related sales for Con Edison as opposed to other utilities. Its position, therefore, is contrary to the Commission's directive in its RDM Order and must be rejected.[256]

Nothing in the RDM Order mandates that a utility-specific RDM eliminate the risks that a utility currently bears due to fluctuations in weather. CPB concurs with this maintenance of the status quo. As Dr. Elfner explains regarding weather-related electric sales variations and deviations in the number of customers from forecast levels, "the Company is currently at risk for these factors and it should continue to be so under an RDM." (4703).

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[255] RDM Order, p.8.

[256] In addition, this philosophical difference cannot be ignored as a possible driver of the additional criticisms that Staff levies against the Company's proposal, where they focus on eliminating a weather adjustment, rather than proposing a reasonable means to implement it.

NYPA states that they oppose a weather "carve out" because they know of no other electric decoupling mechanisms with such a "carve out." (4655; 2262). It appears that NYPA's knowledge is incomplete. As the Company's RDM Panel testified, "Idaho Power Company's electric decoupling mechanism is based on weather normalized sales rather than actual sales." (2263). Second, it is common knowledge that few electric utilities in the United States have implemented an RDM. Company witness Morin testified that only three investor owned electric utilities currently are operating under an RDM. (2686). Moreover, irrespective of what may be appropriate for other utilities, neither NYPA, Staff, nor any other party to this proceeding has established a nexus between implementing revenue decoupling and removing Con Edison's existing exposure to weather-related variations in revenues.

b) <u>Concerns Regarding Gaming The Sales Forecast Are Unfounded</u>

Staff argues that "[by] including sales deviations caused by abnormal weather in the reconciliations, the dysfunctional incentive to 'game' the sales forecast in the rate case is greatly reduced or eliminated." (3966-3967).

Staff's concern that the Company's proposal provides an incentive to game the forecast is totally unfounded. (2264). The sales forecast will not be set solely at the Company's discretion. (2264-2265). Rather, the sales forecast in this proceeding will either be established through litigation or through settlement and thereafter be approved, rejected or modified by the Commission. (2265). The Company's sales forecast and corresponding testimony, as well as Staff's forecast, have been filed as part of this proceeding, and all parties have had the opportunity to review and question them through discovery and hearings, and will have a further opportunity to explore them either through litigation or settlement. *(id.)* The Company has been subject to a significant amount of discovery related to its forecast, which provides a sound basis

for establishing an agreed upon sales level. *(id.)* In addition, this process is no different than all prior electric rate proceedings where the electric sales forecast is invariably an issue. *(id.)* To the Company's recollection, in all but one of these proceedings, a final sales forecast has been approved by the Commission with the Company remaining at risk for weather. *(id.)* In essence, Staff seems to be questioning the rate-making process rather than the implementation of revenue decoupling. *(id.)*

c) <u>There Is No Need For On-going Regulatory Oversight</u>

Staff expresses concern that the Company's proposed RDM weather normalization requires close on-going regulatory oversight that would generate unnecessary costs for both the Company and Staff. (3967). Staff's concern is unfounded, as the Company's proposed weather normalization methodology is neither unduly complex (and therefore requiring close on-going regulatory oversight), nor should this be a criterion for rejecting a methodology if it is otherwise proper and would produce the desired result. The Company, Staff and other parties expressing interest in revenue decoupling have successfully implemented many highly, more complex procedures in the past to produce desired results (*e.g.*, unbundling). (2266-2267).

First and foremost, any weather normalization under an RDM should be designed to most accurately measure the response on sales of weather variations. The Company's methodology accomplishes this goal while at the same time standardizing many of the factors used in the calculation. As the RDM Panel explained, "all degree days are not created equal." (2267-2268). "Customers' response to weather is not just a function of the number of cooling degree days but is also a function of the weather pattern, *i.e.*, how dispersed these cooling degree days are over the month." (2268, 2304). In other words, even if the same months in different years had the same number of cooling degree days ("CDDs"), the weather patterns of these CDDs often differ.

(id.) The monthly regression models, as proposed by the Company, are based on daily sendout and daily degree-day data and thereby recognize both the number of degree days and the distribution of such degree-days.

NYC witness Chernick tacitly recognizes the importance of the distribution of the degree days in the context of his erroneous assertion that the problem with the Company's weather normalization is that the Company's "weather adjustment would assign to Con Edison the same revenues for ten days that were 1° warmer than normal as for one day that was 10° warmer." (4963). While Mr. Chernick is correct in implying that the impact of weather changes on sales depends on the distribution of the degree days, he is wrong in concluding that the Company's proposed procedure does not recognize this. As explained by the RDM Panel, the Company's proposed monthly regressions of the logarithm of sendout on weather variables do assign a greater customer response to days with higher deviations from normal weather. (2274).

In fact, it is for this very reason that quarterly model coefficients should not be used for weather normalization under an RDM. Quarterly model coefficients utilize quarterly data. Accordingly, the effect on daily sendout of daily degree days would not be measured. Rather, the quarterly effect on sendout would be measured against quarterly degree days, which would not result in the most accurate weather impact.

For example, under NYC's proposal (4968), the quarterly coefficients would be applied to quarterly variations in CDDs. During this period, there could be very hot days with high CDD and other days could be very cool resulting in very low CDD. (2275). Over the quarter, these will offset each other to some extent. *(id.)* For example, the worst case scenario would occur if the number of above normal CDD exactly equaled the below normal CDDs during a quarter. *(id.)* The total variation in CDDs in this case would be zero, resulting in no adjustment to sales,

and hence delivery revenue, due to weather. *(id.)* However, there is no dispute that the actual level of sales would not be the same as if there were no variations from normal CDDs each day. Very hot days have a larger impact on increasing sales than do cooler degree days in reducing sales. *(id.)* Under the Company's proposed mechanism, the monthly regression models relate the actual daily sendout to actual daily degree-days so that this offsetting does not occur and the weather response is more accurately measured. *(id.)* NYC acknowledges that customers' response to different CDD distributions like those in their scenario would not be the same. (4963). Yet, if the Company remains at risk for weather, NYC is proposing to use the Company's quarterly weather coefficients (4968), where this distinction in the pattern of degree days will not be picked up.

Since the goal of the weather normalization is to best measure the impact of weather on sales, the daily effect of weather variations must be measured. No party to this proceeding, except the Company, has proposed a mechanism for capturing these daily effects.

Notwithstanding the viability of the Company's initial proposal, to address the concerns raised by Staff and NYC, the RDM Panel proposed a modification to the weather adjustment in its rebuttal testimony. Specifically, instead of remaining at risk for weather during the entire year, the RDM Panel's testimony explained that the Company is amenable to remaining at risk for weather variations only during the summer months, *i.e.*, the billing months of June through September. (2270). As the list of discrepancies in the weather variables used in comparable months of different years as cited by NYC involves only non-summer months (4965), the proposal to restrict the weather normalization to the June through September period will eliminate this concern.

Accordingly, for parties concerned about the need for ongoing review of the Company's calculations, the Company's modified proposal would reduce oversight that may be appropriate from 12 months to 4 months. (2271).

d) <u>The Company's Normal Weather Assumptions Do Not Impact The Proposed Adjustment for Weather</u>

Staff argues that the Company's assumption of normal weather is inconsistent with the 30-year average of actual CDDs because the Company currently excludes normal CDDs for the months of November, December, March and April. (3968). Even assuming *arguendo* that Staff's assertion is correct, the Company's proposal to limit the weather normalization to the months of June through September eliminates this concern. (2271).

e) <u>The Company's Mechanism Is Not Unduly Complex</u>

Staff, NYC and NRDC\Pace all comment that the Company's proposed weather normalization methodology is too complicated. To cite Staff, "the Company's proposed weather normalization mechanism is based on a sophisticated statistical methodology that is applied on a monthly basis and involves very complicated weather impact allocations between sales and sendout, calendar days and billing days, among days and months, between months and quarters and among service classes." (3967). NRDC\Pace comments "[a]fter weather adjusting a month's sendout, it must be overlaid with the monthly billing cycles, assigned to customer classes, and converted into changes in revenues from each class. None of these steps is clearly detailed and justified in the Company's testimony." (5323). NYC states that "Con Edison's proposal is extremely complicated" before going on to describe the calculated examples that the Company provided in response to DPS 257. (4964-4967).

The complexities alleged by these parties are not a basis for rejecting the Company's proposed mechanism. Many of the factors used in determining the weather impact will be set in

advance, once a year, and need only be reviewed once a year. (2266). For example, the loss factor the Company would use to convert sendout on a billing day basis to sales would be set once a year. The cooling and heating degree day coefficients used for allocation purposes would be set once a year.

In addition, Exhibit 161 contains a step-by-step procedure for normalizing electric sales. In Exhibit 30, in response to Staff Interrogatory 257, the Company provided a detailed explanation of its proposed methodology for weather normalizing electric sales in the context of the RARIM, for calendar years 2005 and 2006. As part of its response, the Company provided its monthly regression models for each month for calendar years 2005 and 2006. The Company also provided all the actual data behind these regression models and worksheets showing the calculation of the calendar weather impact to a cycle weather impact; the allocation of the weather impact on a total sales basis to a service class basis along with the allocation factors; and the actual rates used to price the service class weather impact in order to attain the impact on delivery revenue related to weather variations.

The accurate calculation of the Company's revenue entitlement under an RDM is a critical matter to all concerned. While simplicity is a noble goal, it must remain secondary to accuracy. The parties that raise concerns about complexity have the expertise necessary to test and evaluate the implementation of the RARIM.

For the reasons given earlier, there is no basis for changing the Company's current exposure to weather in implementing an RDM. So long as the process for maintaining the status quo is transparent, it should not be rejected because detailed calculations are required.

In that regard, it bears mention that the Company's quarterly sales forecasting models are also based on sophisticated statistical models, which also require allocation factors to attain a

monthly sales forecast. If such sophistication and complexity is acceptable as a reasonable necessity for forecasting purposes, the same sophistication should also be acceptable for purposes of making computations for a revenue decoupling mechanism.

f) **The Company's Regression Method Does Not Produce A Biased Estimate**

Staff claims that "[t]he regression method proposed by the Company may give a biased estimate for weather impact if the model is not properly specified." (3968). The Company disagrees as there is no statistical basis to reject the Company's proposed weather normalization methodology. The weather coefficients of the monthly regression models, which are the bases by which the Company proposes to determine the total weather impact, are not biased even with the presence of first order autocorrelation. Staff RDM Panel witness Liu agreed "in econometric theory that the estimates of the coefficients from least squared regression are unbiased even in the presence of first order autocorrelation." (3979).

While there are no Autoregressive ("AR") terms in the Company's monthly regression models as reflected in the Company's quarterly forecasting models, this is not a concern as the Company's quarterly sales forecasting models and monthly regression models are developed for different purposes. (2305-2306). The purpose of the monthly regression models is simply to determine the impact of weather on sales. (2305). The quarterly forecasting models are developed to forecast the Company's sales. (2306). While the monthly regression models exclude AR terms, which would reduce serial correlation and hence the efficiency of the estimation of the regression model, this does not imply that the weather normalization is biased. It only implies that the standard error of the monthly regression is biased. (2307-2308). This would be a concern if the monthly models were being used to forecast the Company's sendout as the standard error measures the possible spread between the estimated and actual sendout. Since

these monthly regression models will only be used to determine the weather impact on sendout, the bias in the standard error is of no concern in this process.

g) The Weather Impact Is Priced Net Of The Customer Charge

NYC criticizes the Company's proposed methodology for pricing the weather impact because it includes customer charge revenues in its calculation of the actual average price. (4967). NYC is incorrect. As set forth on Line 4.a. of Exhibit 161, provided as part of the Company's RARIM supplemental testimony, the Company's proposal explicitly provides "[c]alculate the actual monthly average price for each service class by dividing the total Delivery Revenue (net of customer charge)…." (emphasis added) In addition, Mr. Rasmussen states "[c]ustomer charge revenues will be excluded in calculating the actual average monthly rates." (2247). The worksheet provided as part of Exhibit 30, showing the calculation of the weather impact for calendar years 2005 and 2006, also explicitly states that the average rate by SC excludes the customer charge. In fact, Mr. Chernick admitted during cross-examination that the Company's pricing proposal did indeed exclude customer charge revenues. (4993).

2. Gaming the Customer Forecast

Staff raises a concern in relation to "gaming" the customer forecast under the Company's RPC proposal. (3972). As explained above regarding concerns about gaming the sales forecast, Staff has not established a reasonable basis for this concern.

First, the Commission must approve the customer forecast, which would be the basis of any RPC factors used to determine the allowed revenues. (2278). The Company has many years of historical customer counts by service class that can be used as a basis for reasonableness. *(id.)*

Second, the Commission just recently approved a RPC mechanism as part of the 2007 Gas Rate Plan. *(id.)* Nothing in the record in that case suggests gaming concerns regarding a customer forecast in developing an RPC mechanism. *(id.)*

Third, the concern raised by Staff is equally applicable to its own proposal. That is, assuming *arguendo* that the Commission were to adopt Staff's total revenue proposal, the total delivery revenue forecast for many of the service classes, which will be the allowed delivery revenue under Staff's proposal, is also dependent on a customer forecast. Therefore, to imply that the Company's RPC proposal cannot be adopted due to gaming concerns related to the customer forecast also implies that Staff's proposal cannot be adopted.

3. <u>Miscellaneous Comments Regarding The Company's RPC Proposal</u>

NRDC/Pace witness Greene states "I believe that per customer revenue decoupling is generally a good approach." (5325). He does, however, argue that there are some customer classes where an RPC mechanism is not appropriate. *(id.)* While NYC recognizes that the customer variable may be an important variable for small customers, such as service classifications 1 and 2, and may need to be included in setting the revenue target, the City also argues that certain service classes, such as SC 9, exclude the customer variable from its forecasting model and for them an RPC mechanism is therefore not appropriate. (4961).

First, NYC is incorrect. Mr. Chernick acknowledged, during cross-examination, that the SC 9 forecasting model does include the customer variable. (4991).

Second, while the Company's forecasting models for SC 4, 8, and 12 do not explicitly relate the sales levels to the number of customers, this does not mean that the customer variable is not an important driver of sales, and cannot be used in setting RPC targets. (2288). Rather, it just means that the customer and employment variable may be too highly correlated to include

both in the model, and for forecasting purposes, the model with employment as an independent variable may provide a better forecast. *(id.)*

NYPA is concerned that NYPA and EDDS are both treated as one customer under the Company's RPC mechanism and that any change in usage will flow directly into a RARIM adjustment, which will eliminate the economic incentive for NYPA customers to pursue DSM. (4655).

NYPA is incorrect that the RARIM adjustment will eliminate the economic incentive for NYPA customers to pursue DSM. (2339). NYPA customers who pursue DSM have a significant opportunity to save through a reduction in supply costs (supply represents approximately seventy-five percent of NYPA's total costs) and through a reduction in their delivery costs due to reduced usage assuming NYPA passes any RARIM adjustment to all NYPA customers and not just to those who pursue DSM. The Company's proposed treatment of NYPA and EDDS is no different than the proposed treatment for other service classifications. (2338).

4. <u>Proposed Modifications to the Company's Proposal</u>

NYC and NRDC/Pace proposed to determine the allowed sales (for those service classes where an RPC would not be appropriate) by updating the Company's quarterly sales forecasting models. (4962, 4967-4968, 5326). The Commission should reject this modification.

NYC and NRDC/Pace proposals do not address or resolve the criticisms leveled on the Company's proposal, and furthermore, do not provide any benefits or improvement to the Company proposal.

First, while NYC has argued that the "decoupling mechanism should be as simple, fair, and transparent as possible" (4959), their proposed modification fails to meet this standard.

NYC's suggestion to adjust revenue targets for those classes that exclude the customer variable, based on the Company's sales forecasting models, is neither simple nor transparent. NYC considered the Company's weather methodology to be too complex and does not want to review twelve monthly regression equations. Yet, as discussed *infra*, they would review quarterly updates of the Company's sales forecasting models, the actual data that is updated each quarter, the allocation of the quarterly forecast to monthly volumes, the calculation of billable demand, and the pricing of the monthly forecast by service class using the Company's 26 pricing models to establish appropriate allowed revenue levels. This process is hardly a model of simplicity. In the Company's view, it would entail significantly more oversight than the Company's weather normalization procedure, which was criticized by NYC for its complexity and lack of transparency.

In addition, the Company would have to update on a quarterly or annual basis the values of the independent variables in the sales forecasting models to reflect the actual real electric price, actual private non-manufacturing employment and actual number of customers, as well as actual weather (if a normalized approach is approved) to get the level of allowed sales. (4967-4968, 2281). However, the allowed target under a revenue decoupling mechanism is not an allowed sales target but rather an allowed delivery revenue target. NYC never explains how the allowed delivery revenue would be obtained from an allowed sales level except to say that the equations adopted for forecasting sales and revenues in this proceeding can also be used quarterly or annually to adjust the revenues for the revenue decoupling mechanism. (4967-4968). They have left it to the Company and other parties to this proceeding to determine how this would be done in accordance with the Company's forecasting methods. Accordingly, the

NYC's modifications are not ripe for implementation. Additional procedures would be required to first understand and then evaluate NYC's proposal.

NYC also argues that the Company should bear some of the pain in an economic downturn and share some of the benefit in an economic upturn. (4961). Contrary to the NYC's implications, the Company will be at risk for downturns in the economy under the RARIM. Under an RPC mechanism, like the RARIM, the Company is at risk for the level of customers above or below the forecasted level. Economic downturns often result in a loss of customers as businesses fail. Even if there isn't a loss of customers but rather a slower increase in the number of new customers than reflected in the agreed upon forecast, the result will still be less revenues.

In addition, as stated above, NYC's approach does not address many of the criticisms they cited against the Company proposal. (2282). For example, NYC's approach does nothing to alleviate their concern regarding the movement of customers from one service class to another or a reclassification between service classes. *(id.)* Since the forecasting model for SC 9 does incorporate the number of customers, if an SC 2 customer moves to SC 9, the Company will get additional revenues under the NYC proposal just as they would under the Company's RPC proposal. *(id.)* This movement between service classes, however, is not an issue that should raise concerns. *(id.)* To take service under a particular service class, a customer must qualify under specific, defined tariff criteria. The Company cannot ignore these criteria and arbitrarily transfer its customers among service classes.[257] In fact, customer movement between service classes occurs naturally when either a customer expands its operations or when a customer contracts its operations. *(id.)* This change in operations can lead them to become eligible for a different rate under another service class. *(id.)* This type of movement can happen in either

[257] As to the establishment of new service classes, they would be subject to the Commission's rigorous tariff approval process.

direction, so that the Company can either gain or lose revenue under a RPC mechanism. (2282-2283).

In fact, the very example that the Mr. Chernick provided in his direct testimony of a master-metered SC 4 or SC 8 being re-metered so that each apartment or office is a separate SC 1 customer would likely result in a loss of revenue to the Company under an RPC mechanism, not an increase. As Exhibit 160 shows, a loss of one SC 4 customer would result in a loss of $187,350.08, while a gain of one SC 1 customer would result in an increase of only $545.41. The one SC 4 customer would need to be re-metered to a minimum of 343.5 individual SC 1 customers to break even, let alone make any money under the NYC's example.

Second, reclassifications of customers between service classes should not be an impediment to the adoption of a RPC mechanism. (2283). To the extent reclassifications have the potential to be significant, the Company is open to making an appropriate adjustment to the mechanism, where allowed revenues would be adjusted accordingly. *(id.)*

Third, NYC recommends there be a distinction between the time-of-use and non time-of-use customers within service classes. (2283, 4961). However, the Company's forecasting models only forecast total class sales, and do not provide for such a breakdown, nor does NYC elaborate on how this would be accomplished. (2283).

In addition, there are issues with the updating of certain independent variables in the forecasting models in determining allowed sales levels. (2284). For example, NYC wants the models to be updated to reflect actual real electric prices. (4968, 2284). However, as explained by the Company's Forecasting Panel, "[f]or forecasting purposes, we assumed that the real electric price remains at the 2006 level and does not include the April 2007 rate increase." (539, 2284). Any updating of real electric prices is likely to reduce the allowed sales levels as the

updated real electric prices are likely to be higher than the level assumed in the sales forecast. (2284). The level assumed in the sales forecast excludes both the requested rate increase related to this filing as well as the actual rate increase that went into effect April 1, 2007. *(id.*) Therefore, updating the real electric price would not provide a consistent comparison and would lead to an understatement of the allowed sales and hence, allowed revenues. *(id.*)

Finally, the actual private non-manufacturing employment data ("employment)" for New York City is revised once a year to reflect a larger population sample ("benchmark revision"). Normally, this benchmark revision only affects the previous two years, but data further back than two years can be revised if new information is available. (2284-2285). This can lead to an inconsistency in the employment data used in the sales forecast and the actual employment data used in updating the models to determine allowed sales. (2285). For example, the actual fourth quarter 2006 private non-manufacturing employment is 3,385,000, and is projected to be 4,000,000 in the 3rd quarter 2008. *(id.)* These figures were reflected in the Company's forecasting models in determining the Company's sales forecast. *(id.)* Staff also accepted these figures. *(id.)* Once a year, New York State Department of Labor restates the actual employment levels based on a larger population sample. *(id.)* Usually, this revision extends back two years. *(id.)*

Now, let's assume it is October 2008, and the Company is updating their models for actual employment data as part of the City's RDM proposal. *(id.)* The 4th quarter 2006 actual employment is now 3,100,000 based upon the New York State Department of Labor benchmark revision. (2285-2286). Assuming the growth in employment remained the same, the 3rd quarter 2008 actual employment would be 3,663,220 [(4,000,000/3,385,000)*3,100,000]. (2286). If the Company ran the existing models, set at the time of the rate proceeding, the Company would be

penalized for this decrease in employment in the 3rd quarter 2008 from the level assumed in the rate filing (3,663,220 vs. 4,000,000) when in fact, the actual updated, in this case, is exactly the same as the forecast level when put on the same basis, and should have no impact on the allowed sales. *(id.)*

As demonstrated above, the City's proposal does not provide any improvements over the Company proposal and should therefore be rejected.

D. <u>Impact of the RARIM on Investor Expectations</u>

The RDM Order left to individual utility proceedings whether an RDM should affect a utility's allowed rate of return.[258] More important, the RDM Order (pp. 14-15) recognized:

> That while decoupling of utility sales and delivery revenues shifts some business risk from the utility to customers, without examining the specific delivery revenue design mechanism in conjunction with other factors and terms of a given rate plan, it is unclear to what extent, if any, utility risk is affected.

The Company's views as to the impact of the RARIM, or an alternative revenue decoupling mechanism, on rate of return is addressed in elsewhere in this Brief.

Also important from an overall perspective is that eliminating the Company's opportunity for additional earnings from hot weather will impact investor expectations. As stated by Dr. Morin and Mr. Hoglund, the Company already has one of the lowest allowed equity returns in the country, which manifests itself in a very low market to book ratio, and that is with the opportunity to earn if the weather were extremely hot. (2277). Couple that existing framework with other proposals in this case for an even lower equity return, more penalty-only rate mechanisms and proposals to exclude from its revenue requirement costs that it must nonetheless continue to incur, and the Company's ability to attract investors would necessarily be impacted negatively by these material changes in ratemaking. *(id.)*

[258] RDM Order, at 14-15.

No weight should be given to Staff's dismissal of the Company's concern about investor expectations, which is based upon the Company's responding in discovery that it had not performed a study or analysis of investor reaction in this regard. (3970). A formal study or analysis is not needed to reach a reasonable conclusion that the Company will become an increasingly less attractive investment to the extent that opportunities for additional earnings are diminished or eliminated. (2277). Accordingly, whatever revenue decoupling mechanism is adopted by the Commission, it should allow the Company to continue to remain at risk, and reward, for weather variations.

It also bears mention that the Company incurs additional expenses even during summers where the weather turns out to be cooler than normal as the Company must be prepared for the possibility of hot weather. (2276). These preparatory expenses are a cost of doing business that are not based on actual weather experienced, but rather are based on the potential for hot weather and the need for the Company to prepare for that potential. *(id.)* Moreover, since calendar year 2006, the Company has adopted additional procedures that are implemented when there is a potential for a very hot day, and not just when hot weather actually materializes. *(id.)* These measures are primarily preventive in nature and are undertaken in advance so that even if the day turns out to be cool, costs are still incurred by the Company. *(id.)* The ability to retain hot weather revenues is important to the Company's ability to defray these expenses.

E. <u>Timely Recovery of Cost Reconciliations</u>

Under the RARIM, the Company would accrue variations from allowed revenue levels on a monthly basis. At the end of each rate year, it would reconcile, by service class, the actual weather-normalized delivery revenues to the allowed delivery revenues and make refunds to customers if the actual weather-normalized delivery revenues are more than the allowed delivery

revenues and surcharge customers if the actual weather-normalized delivery revenues are less than the allowed delivery revenues. (2242-2243). Customers would be surcharged or credited on a volumetric basis over the next twelve months. (2243). In addition, to avoid the potential for a substantial year-end surcharge or credit, the Company further proposed to commence interim surcharges or credits if the cumulative monthly accruals for the combined service classes (including NYPA and EDDS), equal or exceed $10 million at any point during the rate year. *(id.)*

As noted by Mr. Rasmussen, "the lesson learned during the period of the current rate plan is that cash flow is very important to the financial integrity of the Company, and the delayed recovery of expenditures in excess of recoveries provided for in the base rate setting process has a detrimental effect on the perception of the Company by the financial community and on the Company's ability to meet current obligations." (2448).

Staff proposed that reconciliation be implemented six and twelve months from the beginning of the rate year. (3971). NRDC/Pace believe true-ups should be done as often as practical. (5321). CPB supports the Company position of "monthly tracking of accruals, as well as immediate bill credits or surcharges if cumulative amounts equal or exceed $10 million." (4704-4705). NYC sees no reason that revenue decoupling be computed monthly since quarterly or annual calculations should be adequate." (4967). However, NYC also believes that there may be advantages to speeding up or slowing down recovery to moderate swings in other rate components. (4968). NYC suggests that the Company propose a cost-recovery period in each RARIM filing but provides no guidelines for determining either an appropriate recovery period or when moderation of swings in other rate components would be appropriate. *(id.)*

As to computing variations monthly, it is only by computing these variations monthly that the Company will be able to track the deferrals and implement interim refunds or surcharges. Implementing interim refunds or surcharges has the benefit of moderating large bill impacts. In addition, the Company will need to accrue revenue variations as well as interest on the over/undercollected balance under an RDM on a monthly basis as the Company has a formal accounting closing each month.

As to Staff's proposals for semi-annual and annual reconciliations, the Company believes its approach is preferable but, as indicated by the RDM Panel, it is not opposed to a six-month and annual true-up. (2291). While the Company is not opposed to this concept, it should not be implemented in a manner that would require Commission action to determine the recovery period each time a surcharge or credit is to be applied.

F. <u>Miscellaneous Concerns</u>

CPA witness Dowling raises concerns about revenue decoupling as a general matter, directing no specific criticism at the mechanism proposed by the Company as compared to an alternative approach to revenue decoupling. (4811). CPA can continue to explore these concerns should the Commission decide that further study of the revenue decoupling is warranted before implementation for the Company, as recommended by CPB and Westchester.

Mr. Dowling also expresses concerns that "[i]n the past, various decoupling schemes have become untenable because of large deferred revenue balances caused by lower than expected sales;" that "[s]ubsequent recovery of the balances results in excessive bill distortions, particularly if the recovery occurs during a period of higher than expected sales;" and that "[n]othing in this latest RDM leads us to expect better results than in the past, except that it excludes large volumes of sales to demand billed customers." (4811). In this regard, Mr.

Dowling is incorrect. For example, the Company's proposal provides for an annual reconciliation of deviations for forecasted revenues, and for more frequent reconciliations should the amount accrued be equal to or more than $10 million. (2242-2243, 2291). Moreover, the Company has proposed that the RARIM reconciliation mechanism could be expanded to also consider other outstanding deferred credits and debits, thereby further mitigating the volatility in rates. (2442).

Mr. Dowling is also mistaken that the Company's proposal excludes large customers under mandatory hourly pricing. (2290).

RESA/Direct similarly requests that the Commission defer consideration of revenue decoupling for the Company. (5168). Like CPA, RESA/Direct questions the need for revenue decoupling without identifying any aspect of the Company's RARIM that should be modified or eliminated should the Commission nonetheless decide to implement revenue decoupling for the Company. (5166-5169).

Finally RESA/Direct raise a concern that the RARIM could create problems for ESCOs and the competitive market, stating that the RARIM (or, for that matter, any RDM) could result in distribution rates increasing as a result of energy efficiency, which could make the Company's distribution rates less predictable. (5167-5168). This concern is unfounded. As explained by the Company's RDM Panel:

> while the ESCOs may not be able to predict the surcharges or refunds under an RARIM, it should not affect their operations. The surcharge or refund will not be part of the Company's base delivery charge. It will be included on the bills of all customers included in an RARIM. Therefore, it will not affect the competitiveness of ESCOs. The ESCO can market the savings based on their base delivery charges. In addition, any energy savings will also have the effect of reducing any surcharge amounts billed to the customer as the surcharge will be collected on per kilowatt-hour rate. If the customer's usage decreases due to energy efficiency, their portion of any surcharges will also decrease. (2289-2290).

The Company also notes its disagreement with RESA/Direct's assertion that the Company has not demonstrated that "any existing or proposed energy efficiency or DSM program might result in reductions to its delivery service net revenues that would constitute a significant disincentive to its implementing such programs." (5166-5167). As explained by the Company's RDM Panel, the Company estimates lost delivery revenues related to the DSM programs proposed by the Company to be approximately $25.5 million in RY1 alone, which the Company does not consider to be insignificant. (2289).

1. <u>Implementation Date</u>

The Company proposes that its RARIM be implemented effective April 1, 2008, when new electric rates in this proceeding would take effect.

CPB witness Elfner proposes, on the one hand, that the RDM be in place by April 1, 2008 to remove a financial disincentive to promote DSM (4705), and, on the other hand, that the Commission establish procedures to fully address all aspects of the program (as part of the collaborative for an interim DSM program that he recommends) in time for a Commission decision no later than March 2008. (4706). Mr. Elfner's proposal is, on its face, impractical, since the Commission is not likely to act on the record in this proceeding prior to its March Open Session. Moreover, the basis for his concern is that the Company has not fully explained the details of its proposed RARIM. Contrary to Mr. Elfner's assertions, the Company has provided a full and detailed explanation of its proposal, including specific implementation procedures, which is both transparent and straight-forward. Moreover, it bears reiterating that if the Commission were to find that the Company has not fully explained its proposed mechanism, there is certainly no other mechanism before the Commission that has been explained in any detail whatsoever.

Westchester proposed that it was premature to finalize an RDM and that the Commission should established a separate phase of this proceeding in which to consider such a mechanism. (5473-5474). Westchester claims that its recommendation is consistent with the RDM Order, which "suggested that these (RDM) issues may be too complex to include in rate cases." (5474). This interpretation of the RDM Order is curious, to say the least, as the focus of the order was that these issues are best considered in individual utility rate proceedings.

As Mr. Rasmussen explained, implementation of the RARIM on April 1, 2008, is not an essential component of the Company's comprehensive rate proposal. (2408). Accordingly, its implementation could be delayed without objection by the Company, as the driving force behind the RARIM was the Company's filing in compliance with the RDM Order. (2407-2408).

On the other hand, consistent with the State's and NYC's energy efficiency goals, Mr. Rasmussen further explained that the Company did view its proposed energy efficiency programs as an essential part of its overall proposal. (2408). If that program were effectuated other than in conjunction with the RARIM, a lost revenue recovery clause would be necessary and appropriate pending implementation of a viable and reasonable revenue decoupling mechanism. (2408-2409).

2. <u>Continuing the RARIM Beyond The Rate Year</u>

The Company proposed that the RARIM be in effect for three years, consistent with its proposed three-year rate plan. Absent implementation of a multi-year plan, the Company proposed that the RARIM terminate at the end of the rate year. (2242).

Staff, who elected to not address the Company's proposed three-year rate plan, supports the continuation of the RDM beyond the rate year but makes no specific proposal as to how such continuation should be implemented. That is, the Staff RDM Panel "informed the record" of

their position that an RDM should continue beyond the rate year, did not propose a specific process for doing so, and recognized that additional processes would be necessary to effectuate its continuation. (3976).

If Staff believed that an RDM should be continued after the rate year in the absence of a multi-year agreement, it had more than adequate time to form such a proposal. Consideration of an RDM in this proceeding is the result of the Commission's duly acknowledging in its RDM Order that RDM mechanisms have various implications and effects and therefore should be continued in individual utility rate proceedings. Staff's approach ignores this critical aspect of the Commission's findings in the RDM proceeding and would subject the Company, inappropriately and inequitably, to the vagaries of Staff's unstated and unexplained "additional processes" in continuing an RDM for a second rate year, and possibly beyond.

XII. DEMAND SIDE MANAGEMENT/ENERGY EFFICIENCY

The Commission should adopt Con Edison's proposal to continue and expand its energy efficiency efforts for its service territory. Con Edison's proposed program would minimize adverse effects on the environment and would be consistent with the energy efficiency goals of the State, New York City and other local initiatives. None of the parties to this case seriously contests the benefits of energy efficiency, although there are disagreements over the programs that should be continued, whether Con Edison should be the lead administrator for energy efficiency program delivery, the need for and design of an incentive, and whether all customers should pay for such programs. For the reasons stated below, the Commission should authorize the Company's proposed energy efficiency program, including the strong incentive and allocation of program costs the Company proposed, without further delay.

As will be demonstrated herein, the Company's proposed program is designed to achieve permanent energy efficiency measures (500 MW by 2016), consistent with current public policy goals, which focus primarily on obtaining permanent energy efficiency. In addition, the Company is well-suited to be the lead administrator for direct delivery of energy efficiency programs in its service territory because of its strong presence, prior and present DSM program development and execution, experience in measurement and verification ("M&V") for permanent energy efficiency, and access to in-house information systems and data. The Commission should also authorize a strong incentive for Con Edison to encourage it to expand its resources and play a significant role in achieving the State's energy efficiency goals. Finally, all customers should pay for the Company's proposed program because all customers will benefit from that program.[259]

A. The Commission Should Authorize The Company's Proposed Program.

1. The Company Has Reasonably Established a Goal of Achieving at Least 500 MW in Permanent Energy Efficiency Reductions by 2016.

The Company has proposed a specific rate plan program as part of its overall plan to achieve at least 500 MW of permanent energy efficiency reductions by 2016. Company witness Craft explained the Company's strategic policy on DSM and provided background for the Company's 500 MW proposal. The Company has long supported cost-effective DSM as an electric resource that can provide for its customers' needs and that can secure important environmental benefits for its entire service territory. For example, the Company successfully implemented an "Enlightened Energy" program, which achieved over 700 MW in peak demand reductions over the ten-year span from 1988-1998. Since 1998, when the Commission

[259] NYSERDA requested a continuation and expansion of its separate Con Edison DSM program. As explained further herein, that proposal should be rejected. The Commission should also reject AGC's claim that the Company should not use DSM to defer the implementation of the East 13th Street load pocket relief project.

transferred responsibility for energy efficiency programs to NYSERDA,[260] Con Edison has provided support for implementation of the NYSERDA programs and for the development of demand response ("DR") programs implemented by the NYISO. In addition, beginning in 2003, the Company developed its targeted program.[261] The Company has also supported equipment and appliance efficiency standards, by, among other things, urging the federal Department of Energy to adopt a more stringent transformer efficiency standard than it originally proposed. (2991).

The Company proposes to commence a new DSM program focused on achieving installed permanent demand reductions of at least 500 MW, equivalent to a large power plant, by 2016. This program target date and the permanent energy efficiency reduction goal were chosen in response to the NYISO's 2007 Reliability Needs Assessment, in which the NYISO determined that there were reliability needs in the State as a whole in the period from 2011 through 2016, and a need for 1000 MW of new capacity in the downstate area by 2016. The Company, as one of the NYISO's responsible transmission owners, proposed that the 1000 MW need could be partially addressed with new supply and at least 500 MW of permanent energy efficiency in its service territory through 2016. (2993-2994).[262]

The Company's proposed program would build upon and expand upon its current targeted program. It would be comprised of a number of different initiatives, including:

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[260] Case 94-E-0952, Opinion and Order Concerning System Benefits Charge Issues, Op. No. 98-3, (January 30, 1998) ("SBC Order").

[261] The targeted program uses permanent energy efficiency to defer Company load relief projects, *i.e.*, T&D upgrades that are necessary to accommodate load growth.

[262] As Company witness Craft made clear, the Company chose 500 MW as a policy goal based upon this downstate area need as determined by the NYISO. (2993-2994). The Company recognizes that it needs to conduct market surveys to develop specific programs that will facilitate the achievement of those goals and has begun to develop those specific programs. (3381-3382; 3444-3445).

> 1) a targeted initiative focused on load relief in certain T&D load areas, where the proposed levels of DSM reductions would result in deferral of Company planned load relief projects (approximately 150 MW by 2016);
>
> 2) programs designed to reduce demand throughout the Company's service territory, which will be based upon Con Edison's highly successful "Enlightened Energy" initiative in the 1990s (approximately 350 MW by 2016); and
>
> 3) the development of new initiatives, including taking full advantage of the Company's coterminous implementation of its advanced metering infrastructure initiative ("AMI") and highly efficient "green" buildings, as called for by Mayor Bloomberg's PlaNYC 2030 (which hold the potential for adding to the gains produced by the two foregoing initiatives).

(2994). In developing new programs, the Company proposes to use the Commission's total resource cost ("TRC") test that it established in an order on demand management issued pursuant to the 2005 Rate Plan. (3003).[263]

Some parties criticized the Company's 500 MW goal as too small relative to the State's "15 by 15" goal, which contemplates the achievement of a 15 percent reduction in electricity consumption by 2015.[264] This claim is specious because the Company is the first to develop a goal for its service territory and no other service territory goals have been established relative to this statewide goal. Moreover, the Company's proposed 500 MW program is only one of the energy efficiency programs that could reduce electricity consumption in the Company's service territory. The objecting parties fail to acknowledge that it is all such programs, not just Con Edison's 500 MW program, that will contribute to accomplishing the 15 by 15 goal. For example, Staff found that a substantial portion of the 15 by 15 goal could be achieved through

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[263] Case 04-E-0572, *Order On Demand Management Action Plan* (March 16, 2006) ("Demand Management Order"). Although NYC has raised concerns over Con Edison's implementation of the TRC test, Con Edison has been able to contract for and obtain MW under the existing TRC test, and does not anticipate that it would be unable to do so if the existing TRC is continued through the next rate plan. Modifications to the TRC are best resolved in the EPS proceeding on a statewide generic basis and not in this proceeding. Any changes dictated by the Commission's decisions in the EPS proceeding, involving the TRC or any other issue, can be reflected in the Company's program on a going forward basis. (3033-3034).

[264] Case 07-M-0548, Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard, Order Instituting Proceeding (May 16, 2007).

improvements in building codes and appliance efficiency standards. (3027-3029).[265] In addition, as provided for in the 2005 Rate Plan, Con Edison's service territory is the only one where energy efficiency programs incremental to the NYSERDA system benefit charge ("SBC") program have already been implemented. Other parties did not take into account that the Company's 500 MW goal does not include the energy efficiency that will be realized under those programs. Finally, the Company has described its goal as *at least* 500 MW and has designed a program that has the potential to exceed that goal. (2994). When all of these relevant factors are properly taken into account, the Company's goal is sufficient relative to the State's 15 by 15 goal.

Similarly erroneous is the claim of some parties that the Company program is unnecessary. (4815). To achieve the ambitious goals that have been established for reductions in the use of energy and carbon emissions, the Commission cannot reasonably rely solely on one entity. It must encourage new programs by experienced and competent administrators, such as electric utilities, so as to marshal all available resources in the state that can effectively and efficiently contribute to achieving the challenging energy efficiency goals. Electric utilities must be involved and play a central role in providing energy efficiency programs. (3031). The Company has outlined a program rationally designed to draw on its previous and continuing experience with DSM in order to make a major contribution toward achievement of the State's long range energy efficiency goals.

[265] Staff has continued this position in its revised proposal just submitted in the EPS proceeding, Case 07-M-0548. Revised Proposal For Energy Efficiency Design And Delivery And Reply Comments Of The Staff Of The Department Of Public Service, at 8 (November 26, 2007) ("The impacts from building codes and appliance standards are so significant, and the lead times needed to effect and implement revised requirements are so long, that we recommend that work in this area begin immediately and not wait for completion of a long-term energy efficiency development process.").

2. Con Edison Should Administer Energy Efficiency Programs in its Service Territory

The record in this case demonstrates that the Company would be the most effective and efficient administrator for delivery of energy efficiency programs in its service territory. Not only can the Company develop, implement and deliver energy efficiency programs in its service territory, it can also integrate the results of these programs into the Company's planning process. As Company witness Craft explained:

> Con Edison, through its T&D load relief planning process, has the opportunity to use DSM as a tool to defer capital expenditures associated with proposed load relief projects. Determining which T&D investments can be deferred results from an iterative process and requires engineering and financial understanding of all load relief options, as well as the load relief planning process (e.g., substation engineering, feeder and transformer design, network design). Con Edison has experience in conducting targeted DSM programs and is in the best position to design a longer range program that will have the potential of deferring certain of the Company's major T&D infrastructure programs. (2998).

The targeted program allows the Company to defer the costs of infrastructure projects though permanent energy efficiency reductions. Under the 2005 Rate Plan, the Company has entered into contracts for up to 86 MW of permanent energy efficiency and is reviewing bids that would enable it to reach its previously established goal of 150 MW during the term of the 2005 Rate Plan. (2997; 3045). Con Edison's experience with its targeted program reinforces its inherent ability to act as the most effective and efficient administrator of all direct energy efficiency programs in its service territory, including wide scale programs.

As explained by Company witness Craft, the targeted program has provided valuable experience to the Company because it has resulted in the development of deliberate and dependable M&V processes, including pre- and post- installation inspections, so that the measures put in place achieve the targeted MW reduction on a permanent basis. (2997-2998). These M&V procedures stand in sharp contrast to NYSERDA's M&V procedures, which rely

"primarily on estimates"[266] and which prompted the Commission to order Con Edison, based upon a Staff recommendation, to conduct the M&V for the NYSERDA programs. (id.) In addition, because experience has shown it is difficult to quantify gains from energy efficiency measures in new construction and total renovation, Con Edison has excluded such measures from the targeted program to provide greater certainty that the MW installed are "truly incremental."[267] (3025).

Con Edison would also be the most efficient administrator of an energy efficiency program for its service territory because it has additional inherent capabilities that make it well-suited for implementing such programs. As Company witness Craft explained, "Con Edison . . . has in place account executives and customer-focused departments, such as Economic Development, Public Affairs and Energy Services, as well as external channels to deliver a portfolio of utility services. This portfolio provides an established vehicle for timely and effective delivery of DSM programs." (2999). Con Edison also has data systems that provide proprietary account, customer and facility intelligence. These systems provide the basis for market research needed to develop successful products and programs that are tailored to customer needs and benefits. As Ms. Craft explained, this "structure is scalable and provides a foundation for implementation of the 500 MW program." (2999-3000).

The unique nature of Con Edison's service territory (most of it is New York City) requires a DSM administrator intimately familiar with its needs and focused on the development of programs specifically geared toward that service territory. Con Edison satisfies those criteria; NYSERDA does not. NYSERDA necessarily has a statewide focus in developing energy

[266] Case 04-E-0572, Memorandum Order at 5 (July 24, 2006).
[267] NYSERDA's testimony concerning the determination of MW achieved in a new construction or total renovation scenario demonstrates the difficultly in measuring achievements for those programs. It can be difficult to determine the baseline from which the energy efficiency measures achievement should be measured given that existing building electricity demand and consumption does not exist. (5237-5238).

efficiency programs, which cannot and does not capture the unique nature of the Company's service territory. For example, when asked to explain why Con Edison's customers receive proportionally less SBC funds than other service territories, NYSERDA explained that many of its programs involve the use of standard offers and Con Edison customers have not availed themselves of those standard offers as much as other customers. (5272) But NYSERDA has not sought to develop standard offers specifically geared to Con Edison's service territory. (5273). This is precisely the kind of program Con Edison could focus on if it were authorized to proceed with the program it has proposed in this case.

Finally, by approving the Company's proposed program, the Commission will authorize an additional DSM program administrator to enter the market and provide programs. Comparative studies on the cost effectiveness of energy efficiency programs suggest that utility-run programs (*e.g.*, in California and Connecticut) can be twice as cost effective as the programs currently run by state agencies and other centralized program administrators (*e.g.*, Efficiency Vermont).[268] Utilities have the ability to be more cost effective because they have the system knowledge that can be used to effectively segment markets, target specific customer needs and implement energy efficiency programs to satisfy those needs. These studies suggest, and the evidence in this case supports, a decision that Con Edison's administration of programs that it develops would be an essential component of the State's plan to achieve significant permanent energy reductions.

It should be noted that the transfer of responsibility for significant demand-side management programs from the utilities to NYSERDA in 1998 occurred as a part of the

[268] National Action Plan for Energy Efficiency, A Plan Developed By More Than 50 Leading Organizations In Pursuit Of Energy Savings And Environmental Benefits Through Electric And Natural Gas Energy Efficiency, (July 2006), ("National Action Plan"), Table 6-3, pp. 6-8 and 6-9. The plan is available at www.epa.gov/cleanenergy/pdf/napee/napee_report.pdf.

transition to a competitive electric energy marketplace. It was not the result of an analysis concluding that NYSERDA would be the most effective and efficient administrator of end-use directed energy efficiency programs, or that utility-run programs were not a cost-effective means of achieving reductions in energy usage. (3031-3032). Rather, a primary driver of that decision was a concern that utilities could discriminate against ESCOs in their administration of energy efficiency programs.[269] Since that decision, however, Con Edison has participated, as permitted by the Commission, in various DSM programs and implemented initiatives involving ESCOs without discrimination. In addition, the Company has contracted with ESCOs to fulfill requirements under its own targeted program. (3035).[270] The purported concern over discrimination by utilities against ESCOs has proved not only unfounded, but it is also now outdated. While ESCOs were fledging entities in 1998, they are now established competitors effectively participating in New York State's retail energy markets.[271]

In short, the Company has all of the tools -- including experience, infrastructure and an interest in the implementation of much needed territory-specific energy efficiency programs -- that are required to be an effective, efficient administrator of successful DSM programs.

3. All Customers Should Benefit From and All Customers Should Pay for Con Edison's Proposed Program.

The Company proposes to fund its DSM program by collecting its costs from all of the Company's customers, including NYPA's delivery service customers. Currently, all customers,

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[269] SBC Order, at 8-9.

[270] RESA expressed concern that Con Edison may usurp the role of demand response providers if authorized to implement its program, but this concern is misplaced. Con Edison's proposed program is for permanent energy efficiency, not demand response. The Company will continue and expand its demand response programs as before, about which RESA has not complained. Third party aggregators have enrolled a significant number of MW in the demand response programs in New York, and the Company has no intention of interfering with this achievement. (3034-3035).

[271] Case No. 07-M-0458, Order on Review of Retail Access Policies and Notice Soliciting Comments (April 24, 2007).

except for NYPA's, pay for NYSERDA and Con Edison energy efficiency programs in Con Edison's service territory. All customers, including NYPA customers, would benefit from and be eligible for cost effective DSM initiatives under the Company's proposed program. In addition, all customers, including NYPA customers, would reap the environmental and other benefits of DSM initiatives. The Company accordingly proposes that NYPA customers pay their share of the costs of the Company's programs. NYPA customers are responsible for a substantial portion of the demand in Con Edison's service territory. (3002-3003).

NYPA's position that its customers should not have to pay for Con Edison's proposed energy efficiency program is without merit. The NYPA Panel stated that NYPA customers should be exempt because they are already paying for and have access to DSM programs. That testimony, however, begs not only the question of whether NYPA customers will benefit from the Company's programs, but also whether NYPA's programs are sufficient to satisfy the DSM needs of NYPA customers or provide all of the benefits that can be obtained through participation in Con Edison's programs. One of NYPA's own major customers, NYCHA, provided evidence that DSM programs available to NYPA customers were insufficient to satisfy its needs for DSM. NYCHA witness Kass testified that if "NYCHA's remaining 268 properties and 135,000 apartments could participate in the [Con Edison] program, the impact on energy savings and CO2 emissions would be significant not only for NYCHA but for the City of New York."[272] (3044). But, unless NYPA customers contribute to paying the cost of the Company's program, they cannot be eligible to participate in that program.

[272] Moreover, NYPA's DSM programs appear to be less cost effective than the Company's programs. The evidence submitted by NYPA shows that, since 1991, the NYPA energy efficiency program has achieved approximately 114,000 kW of reduction at a cost of approximately $700 million, or a cost of over $6,000/kW. (3025-3026). Con Edison's programs have achieved reductions at a much lower cost per kW. (3026).

NYCHA, joined by NYC, implicitly concede that program eligibility requires payment, but propose that the Company negotiate with each NYPA customer that is interested in participating in the Con Edison program. This proposal is unsupported, however, by any evidence as to its efficiency, practicality or cost. Company witness Craft testified without contradiction that this proposal is clearly unworkable and would create an extremely complicated, time consuming and expensive program structure that could not be easily replicated and scaled up. (3043-3044). Since all of NYPA's customers will benefit from and be eligible for cost-effective DSM measures adopted under the Company's proposed program, NYPA should contribute to the support of that program.

Similarly, NYECC takes the position that some customers should be exempted from paying for the costs of the Company's proposed program. NYECC states that because some customers have already invested heavily in their own energy efficiency improvements, they would derive no further energy efficiency benefits. Instead, they will suffer discrimination because they will be expected to subsidize other customers, who have not made comparable investments. (3042-3043).

The record of this proceeding contains no evidence to support NYECC's proposal. First, NYECC has not explained how it would have the Commission determine which customers have invested "heavily" (or even what "heavily" is), or which customers would derive no further benefit from DSM measures. Second, NYECC has not accounted for customers under its proposal who have already "invested heavily" in energy efficiency, but did so with the benefit of energy efficiency incentives supported by other ratepayers, such as SBC programs. (5116-5117). Having received energy efficiency benefits supported by other ratepayers, such customers cannot reasonably claim that they should lend no support to providing benefits to those other ratepayers,

particularly when all Con Edison customers benefit from cost-effective energy efficiency. Third, NYECC has submitted no evidence of the administrative costs of implementing its proposal or any evidence that the benefit it alleges would outweigh such costs. Finally, NYECC has submitted no evidence to support reversal of the Commission's rejection of this same proposal in adopting the 2005 Rate Plan, where the Commission concluded that "information provided in support of such a broad exemption is anecdotal at best."[273] In this case, NYECC has not provided even anecdotal evidence in support of its proposal. Accordingly, NYECC's proposal must be rejected.

4. The Commission Should Authorize the DSM Incentives Proposed by the Company.

As an integral part of its DSM program proposal in this case, the Company proposes financial incentives. First, it proposes continuation of its previously authorized incentive of $22,500 per MW (adjusted upward for inflation) for incremental enrollments in the NYSERDA SBC 3 (or the NYSERDA System-wide program if it is continued) and Con Edison or NYISO DR programs. Second, the Company proposes that the Commission authorize it to retain 20 percent of the "net resource benefits" realized by the expanded energy efficiency program as an incentive to achieve such benefits for its customers. The Company further proposes that it be authorized to retain for shareholders 30 percent of any net resource benefits it achieves beyond the baseline goal of its program as an incentive for such "superior" performance.[274] Finally, the

[273] 2005 Rate Plan Order at 90.

[274] Con Edison provided an example of the incentive it could earn based upon net resource benefits during the term of a three-year rate plan if adopted. (Exh. 207). That example showed that the Company would have the potential to earn $91 million. That example was based, however, on the Company's original plan of achieving 138 MW of energy efficiency during the three-year term of that rate plan. Since the 138 MW goal has been revised downward to 87 MW (discussed, infra), the potential incentive that Con Edison might achieve during the term of the rate plan is now less than that. Moreover, as Company witness Zielinski pointed out, if the Company earned an incentive of $91 million, it would be because the Company would have achieved net resource benefits of $456.8 million for ratepayers. (2730).

Company proposes to retain as an incentive the value of the "greenhouse gas" emission reductions achieved by its program, if they would have value in an authorized "cap and trade" market for such emissions. (3004-3005).

There is substantial evidence in the record of this case in support of the Company's incentive proposals, including the need for incentives, as well as the design and amount of the energy efficiency program incentives proposed by the Company. Some witnesses in this proceeding asserted that no incentive was needed, or that an incentive level substantially less than the one proposed by the Company should be authorized, or that a different design including penalties should be adopted. These claims and the reason they should be rejected as discussed below.

a) <u>The Evidence Demonstrates that Incentives are Necessary.</u>

In light of its widespread recognition in economic studies, reports by government agencies, and regulatory decisions, the need to provide incentives to investor-owned utilities to pursue effective DSM programs that compete with the use of supply-side resources to satisfy customer needs should not be an issue in this case. The Commission approved an energy efficiency incentive for Con Edison in the 2005 Rate Plan.[275] The federal government has recognized the need for such incentives.[276] The National Action Plan for Energy Efficiency endorses utility shareholder incentives for energy efficiency achievements.[277]

The most substantial evidence in the record of this case on the need for and use of incentives in regulation was presented by Company witness Zielinski, who is a former Chairman and member of the Commission, as well as assistant to two previous chairs of the Commission,

[275] 2005 Rate Plan Order, App. I, pp. 71-72.
[276] 16 U.S.C. Sec. 2621(d)(8).
[277] National Action Plan, p. ES-7. Numerous and varied stakeholders were involved in the design of this plan, including state regulatory commission.

and has over three decades of experience in government and private law practice with electric utility regulatory policy. Mr. Zielinski provided an analysis of a variety of incentive regulation measures and the common economic principles underlying those measures. He also provided an extensive analysis of the California Public Utilities Commission's decision recommending DSM incentives for investor-owned utilities and concluded: "The need for a progressive incentive structure to induce regulated utilities to provide economic DSM service is supported by sound economic reasoning." (2727). [278]

CPA witness Dowling claimed in this case that no incentives were necessary because an RDM, which the Commission now requires, addresses the need for more energy efficiency. Mr. Dowling did not provide or cite any report, study or other evidence to support this assertion. Nor did he offer any reasoning in support his assertion. As Mr. Zielinski pointed out in rebuttal, an RDM "is not designed to promote more efficient use of electric energy by consumers, and decoupling revenues from sales only makes a utility neutral relative to DSM." Mr. Zielinski also testified that every report he had read on RDM reached the same conclusion. (2730-2732).

b) <u>The Company's Proposal for a Strong DSM Incentive Should be Adopted.</u>

This case raises issues mainly with respect to the Company's tiered incentive for its own expanded energy efficiency program, *i.e.*, 20 percent of net resource benefits for what the Company actually achieves up to the Company's 87 MW proposed goal, and 30 percent for what it achieves beyond the 87 MW goal for a three-year rate plan period. The Company has not

[278] Mr. Zielinski was quoting from a recent proposed decision of the California Public Utilities Commission which has since been affirmed. California Public Utilities Commission, Decision 07-09-043 (Sept. 25, 2007) ("CPUC Decision"), *aff'g* Interim Order on Phase 1 Issues: Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency Programs, Proposed Decision of Commissioner Grueneich and Administrative Law Judge Gottstein (August 9, 2007). The final decision stated (at 77): "all levels of management and personnel throughout the company, and not just within the energy efficiency division, need to be motivated to view energy efficiency as a core business activity in order to achieve the aggressive energy efficiency and environmental goals of the state."

proposed that it receive any incentive for any energy efficiency improvements achieved through changes in codes and standards, even if those changes are advocated and supported by the Company.[279]

The tiered design of the Company's incentive proposal is well supported. A tiered incentive structure, such as the Company has proposed as part of its energy efficiency program, provides a progressively stronger incentive to achieve cost-effective energy efficiency. As Mr. Zielinski pointed out with respect to the CPUC decision of a tiered incentive to utilities to achieve energy efficiency gains:

> The CPUC decision rationally ties progressive *incentive* amounts to the achievement of progressively higher energy efficiency savings levels, as the Company does in its proposal. The economic rationale is essentially the same as that set forth in my direct testimony (at 11-12) with respect to sharing earnings above equity return benchmarks between shareholders and customers.

(2733). NRDC/Pace witness Greene also endorses the progressive structure recommended in California in his testimony but does not discuss its rationale.

Ms. Craft testified that the Company developed its 20 percent and 30 percent incentive proposal with reference to what utilities in the previously discussed California proceeding had calculated as comparable to returns on supply-side investments. She also stated that the Company was mindful of the New York Commission's well established policy of allowing utilities to keep a percentage of property tax refunds they are able to obtain as an incentive to seek such refunds. (3078). Mr. Zielinski described that policy in his direct testimony:

> In the 1970s, the Commission recognized that utilities had no financial incentive to make the effort necessary to contest assessments vigorously and obtain refunds,

[279] The Company notes that while it has requested a percentage of net resource benefits as an incentive, it has not specifically objected to the suggestion of two parties (NRDC/Pace and Staff) that there should be an overall cap on the incentive the Company could earn. As Mr. Zielinski noted, the size of the cap adopted in California is approximately 25 percent of the program budget, which is much larger than proposed by any party in this case. (2729). In addition, as the California Commission found, incentives relative to expenditures were as high as 50 percent when states had aggressive energy efficiency goals.

> when none of the proceeds could kept for shareholders. Unless the utilities made such efforts, there were no tax refunds to benefit customers. Accordingly, the Commission adopted a new policy allowing utilities to retain a portion of real estate tax refunds. Under that policy, customers receive a lion's share of refunds which utilities have a financial incentive to pursue. (2724).

Using incentives ranging from 10 percent to 25 percent, the Commission has consistently followed and successfully applied this incentive policy to obtain benefits for customers over several decades.[280] As Mr. Zielinski pointed out, the Company's proposed energy efficiency incentive of 20 percent (under which 80 percent of net resource benefits go to customers) is within the range of incentives the Commission has successfully employed. (2760-2761). Mr. Zielinski testified that the Company's proposed energy efficiency program presents "an extraordinary challenge," because it requires "the Company to explain to its customers that the cost of service will increase in the short run, which means rates will be higher than they would otherwise be to pay the cost of programs whose benefits will only be apparent to them in the very long run." (2874). Making his point with rhetorical questions, Mr. Zielinski further testified: "Is DSM more or less important than property tax refunds? Does DSM require a stronger incentive than property tax refunds? It seems to me that 20 percent put in that context is not an unreasonable incentive by any means." (2761).

The other parties presented three objections to the proposed incentives. First, NYC and Staff witnesses suggest that the Company should receive no more than a small percentage of the budget spent for DSM as an incentive. Second, NRDC/Pace witness Greene testified that the Company should be subject to a regime that is similar to the one recently adopted by the California Public Utilities Commission, which includes a progressive incentive structure. This incentive mechanism requires a utility not only to surpass certain thresholds but also to run the

[280] See Cases 06-E-1433, 06-E-1547, Orange and Rockland Utilities, Inc., Order Setting Permanent Rates, (Oct. 18, 2007), pp. 36-37 (and previous decisions cited therein).

risk of penalties for falling short of thresholds. Third, some parties (*e.g.*, NYPA) maintain, without reference to the DSM structure recommended in California, that authorizing the Company to earn a DSM incentive requires that it also be subject to the risk of penalties. On close analysis, the Company's incentive proposal is the one in accord with State energy efficiency policy and should be adopted.

NYC witness Chernick testified, "The incentive should be a small part of net benefits (perhaps 5 percent)," but he also maintained it should be "potentially large enough to attract the attention of Company management." (4975). He further testified: "The incentive should not normally exceed 10 percent of expenditures." (id.). As Mr. Zielinski points out, however, Mr. Chernick provides "no economic rationale" to support his conclusion that 5 percent of net resource benefits as an incentive is "potentially large enough to attract the attention of Company management." (2729). Mr. Chernick attempts to support his contention that an incentive "should not normally exceed 10 percent of expenditures" by referring to DSM incentives in other jurisdictions that allegedly range from 4.4 percent to 4.5 percent of DSM expenditures, but his claim fails in light of the State's unprecedented energy efficiency goals. As confirmed by Staff, the State's energy efficiency goal is the most aggressive in the nation. (4336).[281] Utilities will have a crucial role to play in achieving that goal, and something beyond "normal" is called for. Mr. Chernick's claim that there is a "normal" level of incentives fails to recognize the new emphasis on and ambitious goals for energy efficiency and is, accordingly, contradicted by this recent change in State policy. Indeed, his testimony does not even attempt to explain how his incentive proposal aligns with State policy goals for energy efficiency.

[281] It should be noted that the current California overall goals are much less aggressive than New York State's goals. California's goal is that "55 percent to 59 percent of the utilities' incremental electric energy needs between 2004 and 2013 will be met through energy efficiency." CPUC Decision 07-09-043, p. 26. The New York goal, on the other hand, is for more than 100 percent of incremental electric needs to be met through energy efficiency.

As Mr. Zielinski stated, incentives must be "of a sufficient level" so that, as the California Commission stated, "utility investors and managers view energy efficiency as a core part of the utility's regulated operations that can generate meaningful earnings for its shareholders." (2728). This dovetails with the State's goals, in contrast to Mr. Chernick's principle that incentives must be "*potentially* large enough to attract the attention of Company management." (4975). The Commission should formally adopt Mr. Zielinski's principle and not Mr. Chernick's to conform with the State's goal of aggressively pursuing all cost effective energy efficiency.

Mr. Zielinski's incentive test is also more in keeping with the federal standard for energy efficiency incentives. The Energy Policy Act of 1992 requires state utility regulatory commissions to consider the following standard:

> The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures *are at least as profitable*, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for construction of new generation, transmission, and distribution equipment.

16 U.S.C. § 2621(d)(8)[emphasis added]; *see also* 15 U.S.C. § 3203(b)(4).

Mr. Zielinski's incentive test is also supported by the Lawrence Berkeley National Laboratory report on energy efficiency incentives: "The primary analytic issue is determining earnings comparable to those that would have been earned through the acquisition of resources in lieu of DSM."[282]

Staff witness Saxonis relies on an American Council for an Energy Efficient Economy ("ACEEE") study to suggest an incentive in the range of 5-10 percent of the administrative

[282] S. Stoft, J. Eto and S. Kit, DSM Shareholder Incentives: Current Designs and Economic Theory, p. 22 (Energy & Environment Division, Lawrence Berkeley Laboratory, University of California, Berkeley, January 1995).

budget for DSM. (4248-4249).[283] The California Commission explicitly found that this study limited its consideration to a time period after electric restructuring when energy efficiency achievement and corresponding incentives to utilities were de-emphasized:

> the ACEEE report . . . reviewed energy efficiency incentives after electric restructuring, during which time incentive rates for those states that still retained energy efficiency incentive mechanisms were observed to decline considerably. …. [The 1995 Lawrence Berkeley Laboratory] survey shows incentives in the range of 8.2 percent to 50.3 percent as a percentage of program costs in 1993-1994, as compared to the ACEEE survey results of 3.3 percent to 15.3 percent (also as a percentage of program costs).[284]

The data from the 1993-94 period is more relevant because it correlates with the greater policy emphasis on energy efficiency gains that New York has chosen to pursue. As shown above, those data show incentives as high as 50.3 percent of DSM expenditures.

Mr. Zielinski's test is consistent with ratepayer interests because ratepayers receive the "lion's share" of DSM benefits. (2756). As the California Commission observed:

> More importantly, in considering what is fair to ratepayers, we observe that ratepayers "invest" in both supply-side and energy efficiency resources, irrespective of who puts up the initial capital. The only difference is that for steel-in-the-ground investments (generation, transmission, distribution) ratepayers have to pay not only the cost of the facilities, but also the financing costs (debt service, return-on-equity, and associated taxes) to compensate those that put up the initial capital. In contrast, since energy efficiency expenditures are expensed and reflected in rates immediately, energy efficiency saves ratepayers substantial financing costs. Those cost savings are magnified because a dollar of energy efficiency can displace far more than a dollar of supply-side investment to meet the same amount of kWh, kW and therm energy needs.[285]

While NRDC/Pace testified that this Commission should adopt an incentive program similar to the one recommended for California, his testimony is devoid of any consideration of the relevant differences between New York and California. The California utilities have been

[283] ACEEE, "Aligning Utility Interests with Energy Efficiency Objectives" (October 2006).
[284] CPUC Decision 07-09-043 at 52, 81-82.
[285] CPUC Decision 07-09-043 at 11.

given responsibility for achieving almost all the DSM goals in California,[286] and have been given the opportunity to earn incentives for almost all energy efficiency achievements. There is no entity similar to NYSERDA in California. In contrast, in New York, the utilities and NYSERDA share responsibility for achieving the State's energy efficiency goals (and approval of the Company's proposed program would not affect NYSERDA's continued administration of energy efficiency programs). In addition, California terminated competition for retail electricity customers, while approximately 50 percent of the kilowatt hours in Con Edison's service territory are supplied by an entity other than Con Edison (15 percent by NYPA alone). As Company witness Craft explained in her testimony, there are many other entities (*e.g.*, municipal systems, NYPA, LIPA, and ESCOs) that could have some role in achieving greater energy efficiency in New York State or in Con Edison's service territory. (3028-3029).

The California incentive proposal advocated by Mr. Greene includes penalties. NYPA, City witness Chernick and CPB witness Elfner also suggested that the Company should be subject to penalties for not achieving enough energy efficiency. But none of these witnesses even attempted to demonstrate that a penalty (the amount and structure of which no witness specified) was necessary to motivate utilities to achieve greater energy efficiency.[287] The previously discussed federal standard for incentives in the Energy Policy Act of 1992 includes no mention of penalties. Moreover, as Mr. Zielinski testified, under the California policy advocated by NRDC/Pace the Company could be subject to a penalty even when it achieved net resource benefits for its customers. (2737). He also pointed out that there is no specific behavior to deter here, which is the purpose of penalties: "the purpose of the DSM program is to

[286] California Commission, Decision 05-01-055, Interim Opinion On The Administrative Structure For Energy Efficiency: Threshold Issues (January 27, 2005).
[287] NYPA simply testified that a DSM policy is "asymmetric" and "inappropriate" if it has incentives without penalties, which were unspecified. (4652).

encourage the Company to do more DSM, not to deter it from doing something but to encourage it." (2748). Mr. Zielinski's reasoning is consistent with the Commission's articulated rationale for requiring utilities to implement an RDM: the removal of any disincentive they might have to promote or implement energy efficiency.[288] Accordingly, there is no need for a penalty.

The Commission authorized Con Edison to receive incentives but did not subject it to penalties with respect to promoting retail access, and the same principle should apply here. First, promoting energy efficiency to customers, like promoting retail access service to customers, is not one of the Company's statutory responsibilities under the Public Service Law. (2872-2873). While the Commission offered incentives to utilities to promote retail access service to their customers, the Commission did not attempt to impose penalties on utilities for failing to switch some threshold number of customers to retail access service. The Commission should recognize that, just as it is ultimately the customer's decision whether or not to switch to a competitive service provider, it is also ultimately the customer's decision whether or not to implement energy efficiency measures. The Company can educate and provide an incentive to the customer, but the customer must ultimately decide to make the change. The Commission should not penalize a utility for results that depend ultimately on customer decisions.

In addition, Mr. Zielinski testified that the Commission has a fully effective remedy if it believes that the Company is not producing sufficient benefits through its energy efficiency program. The Commission can, within the bounds of due process, put the Company out of the DSM business. (2735). This is a real possibility in New York given NYSERDA's existence as an alternative entity to deliver efficiency programs.

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[288] Cases 03-E-0640, 06-G-0746, Order Requiring Proposals For Revenue Decoupling Mechanisms (April 20, 2007).

Mr. Zielinski also testified that NRDC/Pace's reliance on the California Commission decision as a basis for penalties in New York was unjustified. He testified that the California recommended decision expressly found that that utilities had been given "ample resources" to manage the risk of penalties. (2737). Such ample resources have been amassed largely because of California's decision to make utilities virtually the exclusive managers of energy efficiency programs in that State. As the California Commission further explained:

> the utilities have access to over ten years of completed studies on energy efficiency load impacts, savings persistence and retention, and implementation "best practices"—many of which were conducted or managed by the utilities—to draw from in managing their portfolios. And finally, the utilities have the ability to manage market and forecasting risks through portfolio diversification, since the penalty trigger is based on the GWh, MW and MTherm savings achieved from a large portfolio comprised of a broad range of energy efficiency activities. In sum, we conclude the utilities have a reasonable opportunity to manage the risk of potential penalties under a risk/reward incentive mechanism that sets the penalty trigger at 65 percent of the individual savings goals.

CPUC Decision 07-09-043 at 33. The utility experience, studies and flexibility described in the California decision do not exist in New York.[289]

5. <u>The Commission Should Authorize Con Edison To Commence its Program on April 1, 2008 When the New Rate Plan Begins.</u>

The Company has proposed a significant new DSM program that is designed to achieve 500 MW of permanent energy efficiency reductions by 2016. As discussed, this program can make a significant contribution toward the State's goal of achieving a 15 percent reduction in electricity consumption by 2015. The Company's program would make a more significant contribution if it can begin implementing the program now. Delay will result in lost opportunities. The Company notes that it already had to reduce its forecasted rate plan reduction

[289] NYC witness Chernick at least recognizes that the incentive should be "only positive, as Con Edison builds capability to deliver efficiency." (4975).

goals (from 138 MW to 87 MW) due to the Commission's denial of its petition to jump start the program prior to April 1, 2008.[290] (3015).

The Company had to reduce the energy efficiency goals for both of its programs, the non-targeted and the targeted, as a result of this delay. The primary reductions came from the targeted program because that program requires that measures be installed and verified by May 1 of each year.[291]

The Company still intends to reach its 500 MW goal by 2016, because the Company now plans to achieve more reductions after the first several years than it would have had the petition been approved. (3016-3017). The Commission, however, should approve Con Edison's proposed DSM program now so that the Company's customers and the environment can begin to benefit sooner rather than later. Moreover, in the early stages of seeking to achieve the 15 by 15 goal, the Commission should authorize utility programs because they will provide important early information concerning the different kinds of programs that may be implemented and the results that can be achieved. Authorizing Con Edison to begin now can only result in benefits, while there are no advantages to delay.

Staff claims that there is insufficient evidence that the existing targeted program is cost effective and effectively administered and that it should undergo an "independent" evaluation before being allowed to continue. Contrary to Staff's claim, the targeted program is achieving what it was designed to achieve and the Company has consulted with Staff prior to the issuance of RFPs and execution of contracts. (3035-3037). The precise nature of the "independent"

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[290] Cases 04-E-0572, 07-E-0688, Order Denying Petition And Referring Issues To Rate Proceeding (Sept. 20, 2007).

[291] The targeted program was developed with reference to specific load relief projects. The Company will need to review this revised schedule against the load relief plan in place at the time this program is approved. (3016). Accordingly, the opportunity to defer load relief projects will be further delayed if the Company's proposed program is not adopted in this rate case and is instead deferred to a later date following completion of Staff's proposed collaborative, as Mr. Saxonis suggests. (4240).

evaluation suggested by Staff is still not clear nor how the costs of that evaluation would be recovered. For example, Staff would only state that Con Edison's current M&V contractor "is an experienced firm that potentially could" perform the evaluation. (4285-4286). Accordingly, the record does not support requiring Con Edison to conduct such an evaluation – or that the need for such an evaluation should prevent Con Edison from continuing with its valuable targeted program.

Staff recommends that the Commission order a collaborative prior to allowing the Company to implement any program. Staff bases its recommendation in part on its belief that Con Edison should not be allowed to implement any program, even the continuation of its targeted program, until the Commission has issued an order in the EPS proceeding. (4238-4239). The Commission should reject Staff's recommendation.

By announcing its ambitious 15 by 15 goal, the State has signaled the end of business as usual. If New York State is to have any chance of achieving this goal, key stakeholders, particularly utilities, should be permitted to move ahead with the implementation of cost-effective energy efficiency programs.[292] Moreover, parties must recognize that the achievement of these energy goals will be a lengthy, but not a static, process. The Company fully expects that its role in this process will evolve over the next decade. Recognition of such evolution, however, does not justify delaying implementation of energy efficiency programs. Con Edison is ready to implement cost effective programs now and can continue with its targeted program to obtain additional permanent energy efficiency reductions. (3018). And it is ready to perform the necessary service territory market research that will facilitate the achievement of greater energy

[292] Con Edison notes it has filed comments in the EPS proceeding as part of a Joint Utilities Group that calls for the Commission to issue a decision in the "fast track" phase of that proceeding that would allow utility programs to go forward while longer term energy efficiency issues are resolved. Comments of Joint Utilities in Response to Ruling Setting Collaborative Agenda and Modifying Comment Schedule (Oct. 15, 2007) submitted in Case 07-M-0548.

efficiency gains. Accordingly, permitting the Company to go forward with its program now would complement the EPS proceeding instead of creating a conflict, as Staff suggests.

Similarly, with respect to Staff's proposal for a collaborative, any new collaborative should be a reporting and consultation collaborative and not a decision-making collaborative.[293] (3019). This collaborative would be similar to the collaborative established in the recent Con Edison gas rate case, which named Con Edison as the chair and provided that it would have to consult with other members of the collaborative. (3383-3385). In other words, if the collaborative cannot reach consensus, the Company should still be able to move forward with programs.[294] A decision-making collaborative will only serve to delay the Company's proposed energy efficiency program. Such was the result under the 2005 Rate Plan, when no programs could be implemented for almost a year while the demand management collaborative completed its work and awaited approval from the Commission. (3019). Indeed, Con Edison's inability to contract for any MW under its Targeted Program for the first year of the 2005 Rate Plan of which NYECC complains, was directly due to delays in resolving that rate plan's collaborative issues. (3041-3042).[295]

The Commission should also reject NYC's proposal to form a DSM Coordination Board. It would add another needless layer of bureaucracy that will impede the expeditious implementation of energy efficiency programs. As witness Craft, explained, even developing the

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[293] The Company supports Staff's proposal to continue the electric demand manage collaborative established in the 2005 Rate Plan.

[294] The process adopted could be similar to the one that existed for implementation plans under the 2005 Rate Plan, *i.e.*, after budgets and general parameters were established, plans had to be filed with the Commission but they were not subject to Commission approval. *See* Demand Management Order at p. 3.

[295] Staff did not propose an expedited collaborative and could state only that the collaborative called for in this case might take less time than the collaborative established in the 2005 Rate Plan because there are fewer issues. (4337). Merely attempting to limit the number of issues from the outset is no guarantee that Staff's proposed collaborative would be able to act more expeditiously. Mr. Saxonis states that "it is essential that the interested parties have an active and more defined role in the development of the program portfolio and the setting of program priorities." (4228-4229). This is precisely the kind of formal collaborative process that can only result in delay.

ground rules for such a board, if it were to be implemented, can be a time consuming process. (3391). NYC claims that the Board would provide "expertise," but it does not explain why this Board is necessary in order to provide Con Edison with this "expertise," *i.e.*, what expertise is lacking and how only the Board could provide such expertise. (3019-3120).

B. <u>The NYSERDA Proposed DSM Program Should be Rejected</u>

NYSERDA proposed that the Commission provide NYSERDA with an extension of the System-wide program that it administers, "with continuing availability of the remaining uncommitted funding and a modest funding increase." (5198). NYSERDA did not propose a MW goal it might achieve if the proposal were granted, nor did NYSERDA specify which programs it would seek to implement or whether it would seek to obtain more energy efficiency or demand response. The Commission should accordingly reject this unjustified proposal.

As a threshold matter, it has been conclusively demonstrated that NYSERDA has spent less than a fair share of SBC funds in Con Edison's service territory. While Con Edison's ratepayers contribute 50 percent of the ratepayer funds for the SBC program, NYSERDA has spent significantly less that 50 percent in Con Edison's service territory for all of its programs. In particular, 38.8 percent of SBC funds for commercial and industrial customers have been spent in Con Edison's service territory, 42.5 percent of residential SBC funds, and 30.2 percent of low-income programs. Finally, 24.8 percent of SBC research and development funds have been spent in Con Edison's service territory. (5269-5270).

Accordingly, to the extent the NYSERDA seeks to spend a "modest" incremental amount in Con Edison's service territory, it should do so by seeking to increase the amount of SBC funds that it spends in Con Edison's service territory. Given the disparity between what NYSERDA receives from Con Edison's ratepayers and what it spends in their service territory, no

justification exists for having Con Edison's ratepayers to continue to pay NYSERDA for a separate program.

NYSERDA's failure to spend a proportionate share of SBC funds in Con Edison's service territory is crucial given the representation it made with respect to SBC under the 2005 Rate Plan. NYSERDA was expected to achieve 300 MW pursuant to SBC 3 in Con Edison's service territory during the term of the 2005 Rate Plan.[296] NYSERDA subsequently filed a petition with the Commission on August 11, 2006, stating that it would be able to achieve only between 85 and 100 MW under SBC 3, a substantial reduction.[297] During cross-examination, NYSERDA's business personnel surprisingly stated that they were unaware that the SBC 3 goal had been reduced from 300 to 85 MW (5214-5215).[298] They also declined to forecast what NYSERDA would achieve under SBC 3 in Con Edison's service territory by the end of the 2005 Rate Plan. (5217-5218).

NYSERDA attempted to sidestep its failure to meet the SBC 3 goal by claiming that it has met the 2005 Rate Plan goals because it has achieved 634 MW under the Rate Plan (5195), but this amount is clearly incorrect and should be disregarded. In order to be able to claim that it had reached this 634 MW amount, NYSERDA counted everything it has ever achieved under the SBC program in Con Edison's service territory since the beginning of SBC in 1998, even though the 2005 Rate Plan began on April 1, 2005.[299] (5226-5228). In other words, NYSERDA counted everything it has achieved during the last nine years (1998-2007), but claimed that it had achieved all these MW in the two years since April 1, 2005.

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[296] 2005 Rate Plan Order, App. I, at p. 62.
[297] Case No. 04-E-0572, Order On Petitions For Modification And Modifying Electric Rate Order (Dec. 22, 2006).
[298] The most that NYSERDA business personnel would say at the hearing was that NYSERDA's own filing "would imply" that the goal had changed from 300 to 85 MW. (5214).
[299] This includes amounts achieved under SBC II, which had been substantially achieved prior to the beginning of the rate plan on April 1, 2005. (5205-5206).

Moreover, because it had already achieved the 250 MW under SBC 2 prior to the commencement of the 2005 Rate Plan, its actual rate plan goal was 450 MW -- 300 MW under SBC 3 and 150 MW under the System-wide program. NYSERDA's actual achievement under the Rate Plan is not 634 MW out of 700 MW, but 185 MW out of its 450 MW goal. (Exh. 340, Table 3).

This track record clearly does not justify allocating to NYSERDA additional funds for a separate energy efficiency program in Con Edison's service territory. First, NYSERDA has not shown that it can accurately forecast what it may achieve in Con Edison's service territory under the SBC program, nor has it been able to produce an accurate account of what it has achieved, as shown by its attempt to use what it achieved under SBC 1 from 1998 to 2001 to demonstrate achievement under the 2005 Rate Plan that began on April 1, 2005.

Second, NYSERDA simply did not take the SBC program into account when it proposed a continuation of the System-wide program with a modest increase for Con Edison's service territory. (5272-5273). At a minimum, the potential for increasing participation by Con Edison customers under the SBC program should have been considered prior to making any recommendations for continuation of the System-wide program.

Third, NYSERDA's programs cost Con Edison's ratepayers more than Con Edison's programs when the same amount of money is spent because NYSERDA requires that Con Edison's ratepayers pre-pay for NYSERDA's programs, before any money is actually spent by NYSERDA. The record in this case shows that NYSERDA has collected almost $93 million from Con Edison ratepayers for the System-wide program, but has spent approximately $9.5 million through July 15, 2007 (of which $5.7 million comprised incentives paid to customers). In contrast, Con Edison only collects funds for costs it has actually incurred under the targeted

program (except for a small percentage for Company labor that is recovered in base rates) after the measures are installed and verified (because Con Edison only pays its vendors after measures have been installed and verified). (3027).[300]

While there is now a renewed State focus on obtaining energy efficiency in order to reduce overall energy consumption, NYSERDA has to date demonstrated only that it is capable of achieving demand response for which monitoring and evaluation, including the persistence of these measures, has not been completed. (5231).[301] While NYSERDA had projected in its implementation plan that 46 percent of the MW it would achieve would be energy efficiency, to date 28 percent of what it has contracted for is energy efficiency. (5305). Accordingly, NYSERDA has simply not demonstrated that it is capable of achieving incremental permanent energy efficiency in Con Edison's service territory.

Moreover, in evaluating NYSERDA's accomplishments to date, the potential for substantial free ridership in its programs must be taken into account. A free rider is someone who would have installed a measure without the incentive, and according to NYSERDA's reports, many of its programs have free ridership rates that range from 25 – 50 percent. (3022-3023). While spillover[302] is sometimes added to a program's accomplishments, NYSERDA

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[300] NYECC complains: "Ratepayers paying for DSM are ill served by efforts to merely 'contract for' MW reductions on paper when there is little in the way of actual installations and actual MW reductions attained during the three-year rate plan, yet 'actual' dollars are expected from Con Edison's ratepayers before installations are completed and before MW reductions are achieved." (5102). This complaint, however, should be directed to NYSERDA, which collects money from ratepayers before measures are installed and verified. Con Edison believes that customers should not pay in advance for DSM programs, and this is another reason for having the Company administer energy efficiency programs and not continuing NYSERDA's separate program.

[301] It should be noted, however, that it appears that NYSERDA has already overestimated the amount of demand response it has achieved. While the only study NYSERDA produced showed that the realization rate (*i.e.*, what is actually achieved vs. what is in the contract) for demand response is 85 percent (5252), NYSERDA has used 105 percent (5261) for all of the demand response MW that it has contracted for under the System-wide program, even though only a "small fraction" has undergone full evaluation. (5231).

[302] Spillover refers to reductions in energy consumption and/or demand in a utility's service area caused by the presence of the DSM program, beyond program related savings of participants. These effects could result from, for

stated that it will not count spillover for its System-wide program. (Exh. 343). Accordingly, NYSERDA's actual achievements in MW will be less than what is currently provided in its reports after it measures and subtracts free ridership.

Some parties have mistakenly assumed that NYSERDA has achieved energy efficiency at a lower cost than anticipated under the System-wide program. For example, NYSERDA and Staff assert that the "cost" anticipated under the rate plan was $746/kW, while the actual cost to date of the contracted MW under the NYSERDA System-wide program has been $351/kW, exclusive of NYSERDA's administrative costs, which it states raises the cost of the program to $380/kW.[303] These parties have failed to take into account that this "anticipated cost" of $746/kW was applicable to energy efficiency programs and not curtailable load programs, which, as discussed above, constitute a significant portion of the MW contracted for by NYSERDA to date. The 2005 Rate Plan provides as follows with respect to the basis for the $746/kW amount:

> Con Edison's funding will be capped on an average initiative-wide per kWh basis at the level NYSERDA spent statewide for eight of nine business/institutional programs *(the curtailable load program is excluded)* from 1998-2003, including incentive payments, implementation costs and an administrative fee to NYSERDA, including any fee for program evaluation, adjusted for inflation and higher NYC costs (25 percent). (2005 Rate Plan Order, Attach. I. p. 69) (Emphasis added).

Accordingly, the cost of curtailable load programs should be excluded when comparing the $746/kW Rate Plan cap to the actual cost of programs. NYSERDA's cost of obtaining MW, after the curtailable load programs are excluded, is much higher than $380/kW. Based upon the information that NYSERDA has provided, Company witness Craft estimated the price to be

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example, additional energy efficiency actions that program participants take outside the program as a result of having participated, or changes in the energy use of non-participants as a result of utility programs.

[303] This initial $/kW amount is correct only to the extent that NYSERDA's reported "achieved" kW amounts are correct, but, as discussed above, it appears that NYSERDA's actual achievement will be lower than it has reported to date.

$720/kW (3022). NYSERDA subsequently provided an exhibit (Exh. 211) that purported to show that the price of energy efficiency obtained under the System-wide program is between $532.96 (for installed measures) and $580/kW (for measures under contract that have not yet been installed). But this exhibit does not include NYSERDA's administrative and evaluation costs, and NYSERDA allocated a category of costs entitled "Apportioned Program Level Costs" on a per kW basis without providing an adequate justification. For example, while the goal of the System-wide program was to achieve 46 percent in energy efficiency, NYSERDA has only contracted for 28 percent in energy efficiency in total, and it has allocated marketing costs to energy efficiency based on this contracted amount. (5304-5305). A correct calculation would have allocated the marketing costs based on the original goal of 46 percent, rather than the contracted amount of 28 percent. Accordingly, the Commission cannot rely on Exhibit 211 as providing an accurate calculation of NYSERDA's costs for achieving or installing permanent energy efficiency.

In sum, NYSERDA has not provided a justification for its proposed program and has not demonstrated that it is capable of administering a DSM program geared toward obtaining permanent energy efficiency in Con Edison's service territory. The Commission should reject the NYSERDA proposal to continue its System-wide program and instead authorize Con Edison to go forward with its service territory focused program. Con Edison would continue to coordinate with NYSERDA on its implementation of market transformation programs such as research and development.

C. The Commission Should Decline Consideration of AGC's Claim With Respect to the Company's Plan to Use DSM for the East 13th Street Load Pocket if Cost Effective.

AGC attempts to insert into this proceeding as an issue the Company's proposal, under the 2005 Rate Plan, to use DSM under its targeted program to defer the proposed East 13th Street

load relief project. Con Edison issued an RFP on August 28, 2007 to defer load relief projects and the East 13th Street load pocket is one of those projects. Con Edison is currently reviewing the bids received but has not yet completed its evaluation. (3045-3046). Con Edison's inclusion of the East 13th Street load pocket load relief project in its most recent RFP was done as part of the 2005 Rate Plan. AGC failed to demonstrate why the inclusion of this project in the Company RFP needs to be considered and ruled on in this proceeding. The Company notes that it intends to award contracts under this RFP by end of this year, well before a decision would be issued in this proceeding.

This timing issue demonstrates why the Commission should not entertain in this proceeding a claim that a DSM RFP issued under the 2005 Rate Plan should be withdrawn. It would undermine the regulatory certainty that is necessary for Con Edison to effectively implement the targeted program, which can make a significant contribution toward achievement of the State's overall energy efficiency goal. Under the 2005 Rate Plan, Con Edison was required to seek commitments for up to 150 MW of demand reductions under its targeted program, which is designed to use permanent energy efficiency to defer a T&D load relief project. The East 13th Street load pocket relief project is one of those projects that Con Edison deemed appropriate for inclusion in its most recent RFP. It would undermine State energy efficiency policy to allow AGC to use this proceeding as a vehicle to prevent Con Edison from going forward with this project if Con Edison finds that it would be cost-effective to do so and awards a contract.[304]

In any event, AGC expresses a mistaken concern that this project requires an "extensive" amount of DSM and that system needs will not be met if the DSM is not obtained. The RFP for

[304] As explained in the testimony of Ms. Craft, the Company awards contracts under the targeted program if the contract price satisfies the Commission's total resource cost test. (3073).

the East 13th Street load pocket requested more MW than previous RFPs, but it also covered a much larger geographic area. For example, under the 2005 Rate Plan, for contracts issued to date, the average MW per year per network to be obtained varies from 0.25 MW/year to 4.0 MW/year with 85 percent of the projects requiring load reduction from a single network. For the East 13th Street project, energy efficiency projects can be implemented across 10 networks to supply the required load relief and thus would require an average of approximately 1.6 MW/year, which is well within the above successfully contracted range. (3045-3046).

Moreover, the Company's Infrastructure Investment Panel confirmed that DSM reductions would be sufficient to maintain transmission flows below thermal ratings and voltage profiles within acceptable ranges in accordance with second contingency design criteria. The Panel testified that if the required amount of DSM cannot be obtained, system needs would still be met, as the Company would still be able to rely on several strategies of mitigation. These strategies include, but are not limited to, incorporation of distributed generation at area stations and customer sites, load transfers, and utilization of extended transformer ratings for up to 300 hours. (2095-2096).

The Commission should accordingly reject AGC's attempt to have the DSM RFP for the East 13th Street load pocket project considered in this proceeding. In any event, the record shows that its claim is without merit.

XIII. CONCLUSION

Based upon the foregoing, Con Edison respectfully requests approval of its filing consistent with the positions taken and the update provided in this proceeding.

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Respectfully submitted,

Consolidated Edison Company
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