Case No. 07-E-0523

INFRASTRUCTURE INVESTMENT PANEL--UPDATE/REBUTTAL

ELECTRIC

Q. What are the names of the members of the Infrastructure Investment Panel ("Panel")?

A. John F. Miksad and William G. Longhi.

Q. Has the Panel previously submitted testimony in this proceeding?

A. Yes.

Q. What is the purpose of the Panel's additional testimony?

A. The additional testimony will: (1) update the Panel's prior testimony for capital and O&M spending; and (2) rebut the testimony of the Department of Public Service Staff Infrastructure Panel ("Staff"), Consumer Protection Board and other parties relating to our initial testimony in this proceeding.

Q. Has the Panel updated its previous Exhibits?

A. Yes, Exhibits IIP-1, IIP-2, IIP-3, IIP-4, IIP-5, IIP-6 IIP-8, and IIP-9 have been updated. MARK FOR IDENTIFICATION EXHIBIT_(IIP-1 REVISED), EXHIBIT_(IIP-2 REVISED), EXHIBIT_(IIP-3 REVISED), EXHIBIT_(IIP-4 REVISED), EXHIBIT_(IIP-5 REVISED), EXHIBIT_(IIP-6 REVISED), EXHIBIT_(IIP-8 REVISED), and EXHIBIT_(IIP-9 REVISED).

CAPITAL AND O&M UPDATES

Q. Are there updates to your initial testimony that you would like to explain?

A. Yes. A few capital and O&M programs require updates. For ease of presentation, we will first discuss the capital program updates and then the one O&M program update.

CAPITAL PROGRAM UPDATES

Q. What Capital projects and programs have changed since the Company's initial filing?

A. There have been changes in the following projects and programs:

- New Area Substations (Newtown, Parkview, York);
- Work in existing Substations (Elmsford, Woodrow);
- Generation Interconnection projects (49th Street Expansion, Astoria East, Corona);
- System Reliability projects (M29, Feeder Replacements, Reconductoring, Transformer Remote Monitoring);
- System Reinforcement projects (White Plains to Rockview, Newtown, Lenox Hill to York);
- Public Safety & EHS (Street Light Isolation, Transformers); and
- PSE&G Wheel.

Since the filing, some project start dates have been pushed back while others have been accelerated resulting in either reduced or increased cash flow during the Rate Year. For ease of presentation, we will present each program and project separately. Much of this update information has been reflected in response to Staff interrogatory No. 498, which is presented by Staff as Exhibit _(SIP-1), pp. 181-190.

Newtown - Establish New Area Station

Q. What aspects of the new Newtown Area Substation project have changed since the initial filing?

A. The Company, in discussions with Staff, agreed to make all reasonable efforts to accelerate the construction and commissioning of the Station to 2010. Since our initial filing we have accelerated the schedule and developed a more detailed scope of work and associated estimate. As detailed in our submitted work papers, this resulted in increased costs for: equipment, construction contracts, transmission; and a decrease cost in labor, and other directs. The effects of these changes are reflected in the tables below:

Original Rate Case Funding ($000s)

Forecast 2008	Forecast 2009	Forecast 2010	Initial Forecast Total
20,000	40,000	60,000	120,000

Revised Rate Case Funding ($000s)

Forecast 2008	Forecast 2009	Forecast 2010	Update Forecast Total
59,000	72,000	45,000	176,000

Q. How does the acceleration of the project schedule impact the electric distribution portion of the project?

A. The acceleration of the project results in increasing the cash flow during the proposed three-year plan from $2 million in 2008; $8 million in 2009; and $10 million in 2010 to $10 million in 2008; $10 million in 2009 and $8 million in 2010, respectively.

Parkview - Establish New Area Station

Q. What aspects of the new Parkview Area Substation project have changed since the initial filing?

A. Since our initial filing, we have realized the need for additional above-ground electrical work and increases in costs for easements / permit; to bore under the East River; and cable. The effects of these changes are reflected in the tables below:

Original Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Initial Forecast Total
49,800	-	-	49,800

Revised Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Update Forecast Total
64,900	-	-	64,900

York - Establish New Area Station

Q. What aspects of the York area substation design have changed since your initial filing?

A. The Company's initial filing reflected a conventional design for the York area station that included four 138/13kV 65MVA transformers and associated transmission cables. In this design, two transformers and transmission cables are required to meet peak loads at the substation and two transformers and transmission cables are available in case of the loss of one or two transformers or their supply circuits. Since our initial filing, we have modified the design of the York area substation to include three 138/13kV 65MVA transformers and transmission cables, and, two 13kV interties.

Q. How have these modifications changed the design of the station?

A. This modification incorporates new substation design concepts developed under our 3G (third generation) System of the Future project. The York area substation will be established with three 138/13kV 65MVA transformers instead of the four initially planned. Additionally, two 13kV connections will be constructed between the existing East 75th Street area substation to share two 65MVA transformers with the York area substation (existing transformers No. 2 and No. 5 at East 75th Street). With a total of eight transformers installed, this design allows up to five transformers to be connected to the York area substation 13kV syn bus or up to five transformers to be connected at the East 75th Street 13kV syn bus.

Q. Are you planning to install any other new equipment at York substation?

A. Yes. In collaboration with the Department of Homeland Security and American Superconductor Corporation, we are planning to install and demonstrate a high temperature superconductor electric cable, with fault current limiting capability, at York substation. The superconducting cable will be a third tie between the two stations and will only be operated by taking one of the two conventional ties out of service. The two conventional ties will be placed in service, whenever the superconductor is removed from service.

Q. What are the benefits of the superconductor demonstration?

A. The superconducting cable has the significant advantage of being able to carry much larger current and power than conventional copper cables. This allows for a compact installation, requiring much less underground space for installation. This effort is intended to demonstrate the technical feasibility of the integrated fault current limiting superconductor power cable as well as a stand alone fault current limiter on our system, which are the state of the art technologies that can complement our future 3G designs.

Q. Please describe the 3G System of the Future and its objectives.

A. Con Edison established the 3G System of the Future project to address the challenges associated with serving a growing demand and expanding the electric system using new and innovative approaches. Specific project objectives include: maintaining reliability, increasing asset utilization, improving operating flexibility, reducing street congestion, using new technologies, and reducing, deferring and avoiding costs.

Initial designs for the 3G System of the Future are based on system reconfiguration to share demand and improve asset utilization. One application is in establishing new substations, where transformers can be shared with another substation in close proximity, supplied from a different transmission source. This concept has been implemented in designing the York area substation.

Q. What are the origins of the 3G System?

A. The project began with international benchmarking of other reliable electric utilities around the world serving dense urban centers, including Tokyo, Osaka, Paris, London, Hong Kong, Shanghai, Sydney, and Chicago.

Several common design elements emerged from international benchmarking efforts, such as reconfigurable system architecture, minimal or no low voltage meshed networks, and extensive use of underground and overbuild construction for substations, including the use of gas-insulated transformers. Many urban areas also employ multi-utility tunnels to minimize underground congestion and street openings.

Q. What is the advantage of incorporating the new design at the York area substation?

A. The 3G design results in the deferral of the fourth transformer and associated subtransmission 138kV cable from 2010 to 2028. The design also eliminates the requirement of the fifth transformer and the fifth subtransmission line, as compared to the conventional design. Additionally, this design results in increased asset utilization at both East 75th Street and York area substations.

Q. Are there any other advantages?

A. Yes. The elimination of the subtransmission line eliminates 3.5 miles of street construction work, much of it down major avenues in the upper eastside of Manhattan. Minimizing the number of subtransmission feeders also reduces overall street congestion in areas that have already become extremely difficult to install new underground assets.

Additionally, in the case of a transmission failure resulting in the complete loss of either East 75th Street or York area substation, the medium voltage 13kV ties between the two area substations will allow for fast partial restoration of the out-of-service networks when capacity is available.

Q. What are the cost savings achieved using the new design?

A. The estimated lifetime savings for the project is $37 million, which is the net present value of projected revenue requirements for projected investments required from 2010 to 2028. This savings includes the deferral of the fourth transformer and the 138kV cable, and the elimination of the fifth transformer and the 3.5 mile 138kV subtransmission cable and trench.

The initial cash flow savings for the 3G York area substation in 2010 is $6 million. This savings includes the fourth transformer and 3.5 mile 138kV subtransmission cable, less the cost of the two 13kV interties connecting the York and East 75th Street area substations. These savings are reflected in Con Edison's updated revenue requirement, as presented by the Company's Accounting Panel.

Q. What is the impact of the new design on the reliability of the area substations and the networks supplied by the York and East 75th Street area substations?

A. Con Edison performed extensive reliability analysis of the conventional design and the new design for the York area substation to compare the reliability of each approach. Reliability was measured by the probabilistic expectation of a loss of load (network) from the area substation. The new 3G design offers an improved loss of load expectation at York, and approximately equivalent probabilistic loss of load at East 75th Street compared to both the conventional design and also compared to the reliability today. The key design attribute that provides for this positive reliability is the installation of two interties between the stations, which allows for sharing of transformers, as needed. Complementing this improvement is the fact that York and East 75th Street area substations are supplied from different transmission sources, the Mott Haven and Rainey switching stations, respectively.

Q. Does the new design meet the second contingency substation design criteria established by the Commission in 1961?

A. Yes. In 1961, the Commission directed Con Edison to design its substations supplying high load density networks "so that the loss of two substation transformers or their supply circuits at one time will not result in interruption of service from the related networks." (Order issued July 19, 1961, no case number), approving findings conclusions and recommendations of Staff report, dated July 17, 1961, and directing Con Edison to comply with recommendations.) With the new design, the East 75th Street area substation can lose any two transformers or subtransmission feeders of the five available to its 13kV bus and still supply peak demand in its networks. Independently, the York area substation can lose any two transformers or subtransmission feeders of the five available to its 13kV bus and still supply peak demand in its networks.

Q. Have there been any other changes to the program?

A. Since our initial filing we have brought the Concept scope/estimate to an Order of Magnitude scope/estimate and received the approval of the NYC Department of Buildings to build in the existing East 74th Street generating station in the space vacated by the retirement of the turbine generator set.

The result of the changes described above is an $83 million increase in project costs due to increases in: Construction Contracts; Transmission; Overheads, AFDC and Escalation; Contingency; and Adjustments in Miscellaneous Labor and Materials.

Original Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Rate Case Forecast Total
46,000	60,000	21,000	127,000

Revised Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Rate Case Forecast Total
79,000	97,000	34,000	210,000

Woodrow - Install 3rd Transformer with 138kV Feeder

Q. What aspects of the Woodrow - Installation of a 3rd transformer with 138kV feeder have changed since the initial filing?

A. Since our initial filing, a significant portion of the original 2007 scope for Woodrow was shifted into 2008. The new deferred service date is a result of our Demand Side Management ("DSM") program. In addition to schedule changes there was an increased cost for cable, and a change to the scope of work including additional equipment (breaker and disconnect switch). These changes are reflected in the tables below:

Original Rate Cash Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Initial Forecast Total
10,000	10,000	4,800	24,800

Revised Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Updated Forecast Total
15,000	22,000	6,000	43,000

Generation Interconnection:

Astoria Phase Angle Regulator and Corona Series Reactor

Q. What aspects of the Generation Interconnection program for Astoria and Corona have changed since the filing?

A. Since our initial filing, there has been a change in service date from 2012 to 2010 due to SCS requested service date. In addition, we developed a more detailed scope of work and associated estimate. Although procurement of equipment may likely take longer, this cash flow will expedite the process.

Rate Case Funding ($000s)

Forecast 2008	Forecast 2009	Forecast 2010	Initial Forecast Total
-	5,000	15,000	20,000

Revised Rate Case Funding ($000s)

Forecast 2008	Forecast 2009	Forecast 2010	Updated Forecast Total
5,000	20,000	35,000	60,000

Generation Interconnection: Expansion of 49th Street Substation

Q. What aspects of the Generation Interconnection project for 49th Street have changed since the filing?

A. Several developers have shown an interest in interconnecting to the W49th Street Substation. However, we have no firm commitment on a specific project or service date. Therefore, funding has been deferred by one year.

Rate Case Funding ($000s)

Forecast 2008	Forecast 2009	Forecast 2010	Initial Forecast Total
10,000	20,000	10,000	40,000

Revised Rate Case Funding ($000s)

Forecast 2008	Forecast 2009	Forecast 2010	Updated Forecast Total
-	10,000	20,000	30,000

Spare Transformer Program

Q. What aspects of the Spare Transformer Program have changed since the initial filing?

A. Since our initial filing we have initiated procurement of transformers to support a strategic increase in our 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 our recent failures at Rainey Substation which led us to amend our spare inventory strategy to insure a high probability of spare availability in the event of a transformer failure.

This has resulted in a need to increase our spare transformer inventory as well as to purchase replacements for spares actually used. In addition, there have been dramatic increases in recent transformer costs, in the basic materials required to manufacture transformers and in response to the new code in NYC requiring lower noise levels.

Rate Case Funding ($000s)

Forecast 2008	Forecast 2009	Forecast 2010	Initial Forecast Total
16,500	12,000	12,000	40,500

Revised Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Updated Forecast Total
21,200	33,960	22,285	77,445

Reinforcement - Feeder M29

Q. What aspects of the Reinforcement - Feeder M29 project have changed since the initial filing?

A. Since our initial filing, there has been a $13 million funding increase in 2008, resulting from deferral of work at Sprain Brook & Sherman Creek from 2007 to 2008 and payment of cable and other equipment in 2008 (instead of 2007), higher fees associated with temporary and permanent easements for the Harlem River tunnel, higher than anticipated costs associated with construction of a tunnel, and additional cost to relocate gas facilities along the proposed M29 route.

The $5 million increase in 2009 resulted from additional AFDC consistent with the current project cash flow and increase in labor cost consistent with current rates. The $12 million increase in 2010 resulted from the service date being extended to 2010 which was not reflected in the original estimate.

Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Initial Forecast Total
130,000	68,000	24,000	222,000

Revised Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Updated Forecast Total
143,000	73,000	36,000	252,000

Replace 138kV Feeders 18001 & 18002

Q. What aspects of the project to replace 138kV Feeders 18001 and 18002 have changed since the initial filing?

A. A detailed design package will be developed in the first quarter of 2008. It is planned to have this package issued, and the construction bids received by the end of the second quarter 2008. Construction is proposed to begin in the third quarter 2008. An outage to replace the first of the two feeders will occur during Fall 2009/Winter 2010, followed by an outage to replace the second of the two feeders during Fall 2010/Winter 2011. Overall, the cash flow for these projects has been reduced during the proposed rate plan period.

Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Initial Forecast Total
25,000	22,000	6,000	53,000

Revised Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Updated Forecast Total
5,000	15,000	20,000	40,000

Replace Feeders 69M41 & 69M45

Q. What aspects of the project to replace feeders 69M41 and 69M45 have changed since the initial filing?

A. This feeder replacement project was originally planned to be performed during the 2008 through 2010 timeframe. In order to shift our design and construction efforts, we have elected to defer this work by two years. This approach enables us to address higher priority work.

Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Initial Forecast Total
17,800	18,000	2,200	38,000

Revised Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Updated Forecast Total
-	-	8,000	8,000

Re-Conductor Feeders 69M61 - 69M65

Q. What aspects of the project to re-conductor feeders 69M61 through 69M65 have changed since the initial filing?

A. This load relief project has been deferred from 2009 to 2012 due to Demand Side Management.

Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Initial Forecast Total
7,000	8,000	-	15,000

Revised Rate Case Funding ($000s)

Forecast 2008	Forecast 2009	Forecast 2010	Updated Forecast Total
-	-	5,000	5,000

System Reinforcement: White Plains to Rockview

Q. What aspects of the White Plains to Rockview System Reinforcement project have changed since the initial filing?

A. The funding for this project is deferred until 2013.

Original Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Initial Total
4,000	-	-	4,000

Revised Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Updated Forecast Total
-	-	-	-

System Reinforcement - Lenox Hill to York Substation

Q. What aspects of the Lenox Hill to York Substation System Reinforcement project have changed since the initial filing?

A. The cash flow is being accelerated by one year. The 2011 funding of $1.5 million is being accelerated into the rate plan year to meet the 2010 required service date.

Original Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Initial Total
-	-	5,500	5,500

Revised Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Updated Total
-	5,500	1,500	7,000

Transformer Remote Monitoring System

Q. What aspects of the Transformer Remote Monitoring System have changed since the initial filing?

A. The program has been extended to 10 years, versus the original plan of a 5 year program. Therefore this reduces the funding forecast from $91.7 million to $57.2 million during the proposed rate case plan. Staff's testimony agrees that the program should be fully funded; it is recommended that Staff correct Exhibit __SIP-2 page 6 of 6.

Original Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Initial Total
31,525	30,416	29,728	91,669

Revised Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Updated Total
20,645	18,617	17,929	57,191

Street Light Isolation Transformers

Q. What aspects of the Street Light Isolation Transformer program have changed since the initial filing?

A. The increase to this program is due to the estimates being modified to include a two-person crew and a major increase in cost of material due to a design change of the connector.

Original Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Initial Total
6,100	6,100	6,100	18,300

Revised Rate Case Funding ($000)

Forecast 2008	Forecast 2009	Forecast 2010	Updated Total
10,950	10,950	10,950	32,850

PSEG Wheel

Q. Please describe what aspects of the PSE&G project have changed since the initial filing.

A. Since the Company's initial filing we have been pursuing a potential extension of the PSE&G 1,000 MW wheel which, if successful, may increase the cost of this wheel during the three-year period. The timing of these potential increases came to light only recently after discussions with the involved parties. We propose that any such increased costs be deferred for later recovery.

Q. Does that conclude your capital program updates?

A. Yes. Next, we will discuss our O&M program update and the Greenburgh Tree Law Program. As discussed in work papers filed with the Company's Preliminary update in August 2007, the Town of Greenburgh passed legislation in June 2007 that regulates how and when the Company can cut down trees on private and public rights-of-way in that Town. The law requires the Company to replant trees in areas deemed by the Town of Greenburg to be responsible for protecting the Town against soil erosion, floods and removing carbon dioxide from the air. It is our understanding that this new law calls for penalties if tree cutting, topping or removal takes place around the electrical lines for reasons other than the Company's systematic maintenance program. Additionally, Con Edison would be liable for tree plantings or some other non-prescribed environmental mitigation dictated at the direction of the Town of Greenburgh. As a result, the amount of incremental funding for the purchase and planting of compatible species equates to $6.1 million per year or $18.3 million for the rate years 2008 through 2010. Please note that the Company intends to challenge this arbitrary legislation.

Q. Does this conclude the update testimony section of your submittal?

A. Yes.

REBUTTAL TO STAFF AND OTHER PARTIES

Q. Do you wish to respond to any of the testimony that was presented by Staff and other parties?

A. Yes. We will discuss Staff's recommended forecast levels for our Transmission Operations; Staff Accounting Panel's testimony regarding the Company Meteorologist; Staff's recommended forecast regarding Improve Reliability projects /programs (Paper Insulated Lead Covered Cable ["PILC"], Network Transformer Replacements >100 percent <115 percent, Transformer Purchase, Replace Obsolete Transformers, Spare Transformer Program, Area Substation Reliability Program); Public Safety and Environmental projects / programs (Oil Minders, Vented Manhole Covers, Street Light Isolation Transformers); Storm Hardening and Response projects / programs (C Truss Program, Autoloop Reliability, #4, #6 Self Supporting Wire, 3-Phase Gang Switch Replacement, Rear-Lot

Pole Elimination, Enhanced 4 kV Grid Monitoring, 4 kV UG Reliability, Overhead Secondary Reliability Program, Transformer Purchase); Miscellaneous Components (Category Alarms, Facility Upgrades, SOCCS - RTU Replacement, Substation Loss Contingency); Environmental (Environmental Risk Program, Pumping Plant Improvement Program); and Security Enhancements. Finally, we will address Staff's Reliability Performance Mechanism proposals concerning service restoration, the remote monitoring system, and the special projects incentive mechanisms, and we will introduce a witness who will address Staff's proposals concerning electric service reliability performance.

Transmission and Switching Stations

Q. Do you agree with Staff's proposal at page 23 to use a ratio of historic spending versus budget to develop the future System and Transmission Operations ("S&TO") budget?

A. No. While a historically based reduction approach could be used for high volume and repeatable programs, it is inappropriate for transmission activities which involve large projects, predominately with service dates defined by system need. The current filing is for $239 million, $208 million and $281 million in 2008, 2009 and 2010, respectively, not the $271 million as stated in Staff's testimony. The S&TO budget is developed based on the most current information available.

This budget is designed to ensure the reliability of the transmission system which is the backbone for supplying the customer load in our service territory. Increased expenditures are needed to ensure the system has the needed capacity to address increasing customer load and generating unit retirement. Additionally, investment is needed to replace and/or refurbish the aging transmission infrastructure and associated equipment. Programs are also essential to improve safety and environmental performance, allow implementation of mitigation strategies to reduce system risk, and to leverage new technologies to provide operational improvement.

At times there are factors that are largely out of the Company's control that occur subsequent to developing budgets, which can cause specific projects to be deferred or delayed. Two such projects are the M29 project and replacing the 69kv feeders on the Queensboro Bridge ("QBB"). These are very large projects which by themselves represent a large portion of the S&TO budget. Due to the requirements associated with Article VII approval process, the M29 project was delayed. The QBB project was deferred due to work on the bridge by the City of New York.

Staff developed a proficiency spending ratio to develop its recommendation for S&TO's capital funding for the rate period, which 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, Staff's Exhibit__(SIP-2) 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. In addition, Staff's methodology to use history to determine future spending appears to penalize the Company for deferring or delaying projects which are not within its control. Since the Company received the Article VII approval in August 2007 for M29, the absence of which caused the past slippage in the project, the Company appropriately anticipates spending the $143 million requested in its updated submission for the M29 project in 2008. This single project represents 93 percent of the funding for S&TO that Staff is recommending for 2008. Such a recommendation will essentially stop other Transmission work.

Rather than simply assume that past uncontrollable events will recur, all projects should be analyzed based on the justifications and detailed project cost forecast submitted by the Company. Additionally, the 40 percent reduction recommendation was made by Staff on an across-the-board basis without identifying any specific projects to be deferred or cancelled. Staff's proposed reduction would effectively limit all transmission system investment to only work associated with M29, emergency response, 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.

Meteorologist

Q. Do you agree with Staff's testimony regarding hiring an in-house meteorologist?

A. No. Although Staff's Infrastructure Panel, in addressing the O&M expenses proposed by the Company, did not reduce or eliminate the funding for this position, Staff's Accounting Panel at pages 32-33 did eliminate funding for this position. Weather has a great impact on our ability to provide service to our customers. An in-house meteorologist would provide the Company with improved, immediate, continuous insight into developing weather systems which can support management decisions that are sometimes required with very little lead time, thereby increasing system reliability. Weather contractors which provide services to many clients across a wide geographical region are not always able to provide such tailored information in a timely manner.

Q. Why does the Company need a meteorologist?

A. Adverse weather conditions, such as thunderstorms, hurricanes, snow/ice, and high winds, can have a marked effect on operation of the electrical system and have the potential to cause extended outages to customers. Expert analysis of weather service data will allow for more effective preparation for these events, thus enhancing the operation of the power system. Conversely, without interpretation of the data by a knowledgeable and trained individual, the reports may be misleading and can lead to actions or inactions that are detrimental to customers.

Q. How will a meteorologist improve the Company's operations?

A. The current use of weather services can cause the Company's operating staff to unnecessarily react to potential events, or to not react timely when action is required, based upon when inaccurate or misleading weather service reports. Unlike operating staff, which is not sufficiently knowledgeable to analyze the weather data underlying predictions, an in-house weather person will be able to evaluate various weather reports as they pertain to NYC and its surrounding area. More importantly, the meteorologist would have access to weather observation data and model prediction output at the same time it is made available to the National Weather Service and weather service contractors. Using this information, the meteorologist would be able to make forecasts even before they are made available from the National Weather Service and weather service contractors leading to more timely critical decisions, such as those affecting manpower deployments.

By having a weather forecaster focused on this responsibility, our system operators will be better able to focus on storm preparations and reliability issues during severe weather periods.

Q. What will you discuss next?

A. Next we will discuss Staff's testimony regarding proposed reductions to key Improving Reliability Programs. Before going into specifics of each program we have a few general statements regarding Staff's testimony.

Q. Please continue.

A. In the Staff Infrastructure Panel testimony, Staff makes multiple references to secondary cable failure caused by overloading. These statements incorrectly imply that secondary cable failure is predominantly caused by overloading conditions.

Q. What are the primary causes of secondary cable failures?

A. Secondary cable failure results from insulation breakdown that is primarily caused by aging, salt corrosion and water ingression due to the harsh underground environment. Based on our historical experience, the majority of the secondary cable burnouts occur over the winter months caused by salt and water ingression when the loading on the cables is well below their normal ratings. There is no data to substantiate Staff's suggestions that secondary cable failures are predominantly caused by overloading.

It must be noted that the reference to the secondary cable failures resulting from overloads during the Long Island City event, albeit true, are an exception to our normal summer operating experience. The LIC network experienced tenth contingency at two separate occasions, which is a rare event.

Q. Do you agree with Staff's assessment of the Company's underground secondary reliability program?

A. No. Staff's criticism of the Company's underground secondary reliability program to replace the aging underground secondary infrastructure is unwarranted and premature. Since the beginning of the last rate case period the Company has adopted a phased approach by targeting underground areas in addition to replacements in the course of all emergency work.

Q. Do you have any further general comments?

A. Yes. The Company strongly refutes Staff's suggestion that poor planning of the underground inspection program has resulted in a drastic increase in the request for additional funding in this rate proceeding. The Company in its last rate case filing had recommended and supported a 15-year inspection cycle given the scale of the program (~250,000 facilities) and the magnitude of the resources required for initial setup and training. Staff mandated a five year goal for the inspection program. Despite our concerns with the time period required to meet the PSC goal and the Company's inexperience with a program of this scale, we set an estimated internal goal of 50,000 unique inspections annually. The Company has exceeded the estimation by completing 120,000 unique inspections in the last two years, or an average of 60,000 unique inspections a year. In fact, the number of gross inspections completed each is year is twice the number of unique inspections due to the focus on the underground secondary reliability and public safety initiative resulting from increased stray voltage testing programs. As a result, additional resources are warranted to meet the PSC mandated goal for completing all underground structure inspections by 2009.

Q. What will you address next?

A. We will turn to Staff's testimony regarding the Paper Insulated Lead Covered Cable program.

Q. Does the Company agree with Staff's proposed reduction to the Company's Paper Insulated Lead Covered Cable ("PILC") program at page 40?

A. No. The requested rate-case funding for the PILC Accelerated Removal program should be restored to the full $39 million. Con Edison has made more than a "minimal effort" to remove the PILC cable from its system. Company records indicate that since year-end 1999 nearly 45 percent of the PILC cable in the distribution system has been removed from service. At this rate it would require seventeen years to remove all of the PILC cable on the system.

In the current rate case, and acknowledging Staff's as well as other parties desire to accelerate the removal of PILC cable, the Company has asked for the additional funding. This funding would allow the Company to remove 900 additional sections annually and advance the removal by 4 years to 2020.

Q. Would you comment on Staff's characterization of the Company's efforts to remove PILC cable?

A. Staff's testimony states that the Company's performance in removing PILC cable has not been acceptable. There is no evidence offered to support this assertion. Since 1999, following the Washington Heights event, the Company embarked on the PILC removal program along with removing thermally sensitive joints. Initially, the program direction was to target and remove the thermally sensitive stop joints and the associated PILC Cable with them. However, this approach was found to be inefficient because it precluded removal of more than the sections associated with these particular joints. Hence, paper cable associated with non-thermally sensitive joints a few manholes away were not removed, even when all of the preparation work associated with them was in place. The new approach was abandoned in favor of targeting paper cable sections first, which would improve a feeder's operating performance regardless of the type of joint. This approach accomplished several objectives. It improved feeder performance, established highly reliable key feeders in a network and eliminated thermally sensitive stop joints. In addition, it has also been the Company's practice to remove additional sections of paper cable associated with cable faults on a feeder. This practice resulted in eliminating almost half of the PILC cable population on the system. Staff's assertion that the Company has made "minimal effort" and that the Company's performance is "not acceptable" is, therefore, misleading and unfounded.

Q. Do you agree with Staff that PILC cable removal should be accelerated?

A. We agree with Staff in general - to speed-up the removal of PILC cable. In fact, the Company's Ten Year Network Improvement Strategy includes an aggressive replacement plan. The proposed plan is to replace 900 more sections per year. On average, the Company's PILC program is budgeted (approximately $23 million) to remove approximately 1,300 sections annually and another 400 sections during emergency repairs. The Company has requested an additional $16 million to accelerate the program to remove about 900 more sections per year. Given the interest Staff has expressed in accelerating this program, the Company was surprised by Staff's recommendation to reduce funding, which would slide the removal date back closer to the original 2024 schedule.

Q. Please continue.

A. Next we will discuss the impact of the reduction to the 100 to 115 percent Transformer Overload Relief program. This program impacts our ability to meet our summer demand requirements for our customers. The Company's Rate Case filing has proposed transformer replacement programs for transformers operating at the following levels:

1. Transformers operating above 125 percent of their contingency ratings;

2. Transformers operating between 115 percent and 125 percent of their contingency ratings; and

3. Transformers operating between 100 percent and 115 percent of their contingency ratings.

Q. Do you agree with Staff's testimony at pages 38-39 regarding this program?

A. Not completely. First, we would note that Staff mischaracterized the Company's transformer replacement programs. Staff states that the Company's three program categories involve transformers operating at various levels above "normal and emergency" ratings. Staff is incorrect. The Company's program deals with transformers that are operating at various levels above "contingency" emergency ratings. With respect to Staff's recommendation, Staff has appropriately recommended no adjustments to the first two program categories but summarily, rejects funding for the third category (i.e., transformers operating between 100 percent and 115 percent of their contingency ratings). Staff's rationale for rejecting this part of the program is that the Company "has provided no record of historical spending for replacement of transformers operating between 100% and 115%".

Q. Please explain why the Company did not provide historical spending for transformers operating between 100 percent and 115 percent of their contingency ratings?

A. Historically, the Company has been replacing 250 units of overloaded cable and equipment annually on average as part of its transformer load relief program. The summer transformer load relief program is a critical, labor intensive and costly activity that must be completed prior to the onset of hot weather.

Replacement of transformers involves a complex process that involves identification of a network overload under the Company's second contingency design, under a specific feeder outage that causes the overload. Each transformer load is carefully analyzed and thousands of computer iterations are required to determine if any one combination of feeder outage will result in an overload, and more precisely the percent overload. With over 23,000 transformers, the engineering analysis process is intensive. Once the overload is identified, engineering drawings, vault construction, local permits, and installation activities and feeder scheduling has to be completed to relieve an overloaded unit. In view of the complexity of tasks involved and the capital expenditures required, the Company has focused on high and medium priority overloads for the summer period. Its resource capacity would have been extremely taxed if it had also simultaneously pursued the large number of units overloaded at 100-115 percent above contingency ratings. Thus, this category of overloads was not historically budgeted for relief. Beginning in 2007, the Company is at a juncture where the high priority overloads are fewer and the 100%-115% overloaded units can now be addressed. Thus, the fact that replacement of these units had to be deferred in the past in favor of higher priority replacements is not a valid reason to continue deferring the replacements indefinitely.

Q. Is Staff's position consistent with their approach to other load relief programs?

A. No. The Company has been relieving all primary feeders exceeding 100 percent of normal and emergency ratings for the past decade, and Staff does not accept even the slightest deviation from this threshold even though historical experience has shown that summer feeder failures are rarely due to overloaded conditions of the failed feeder component. Yet, a similar approach for replacing network transformers proposed at an appropriate juncture to address relief in a timely and efficient manner is rejected by Staff.

Q. What will you discuss next?

A. Next we will discuss the impact of reducing funds to our Transformer programs.

Q. Please describe Staff's recommendation for the Obsolete Transformer program.

A. Staff recommends at pages 28-29 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.

Q. Do you agree with Staff's recommendation?

A. No. Taking a proactive approach to the replacement of obsolete equipment, such as system transformers, is critical to ensuring continued reliable service to our customers. The estimated cash-flow requirement for this program is based on anticipated specific future needs, and the funds provided should not be based simply on historical expenditures. The Company's projected 2008 expenditures for the program are based on the specific scopes and replacement costs associated with ongoing and planned work at West 19th St. and Cherry St. Substations, as well as the requirement to provide funding to initiate the purchase of transformers for future replacement projects.

Q. Are there areas in Staff's testimony at pages 29-30 that you would like to address with regard to the Spare Transformer Program?

A. Yes. The funding required to support this program for the 2008-2010 period cannot be based on an assessment of historical equipment performance trends and incurred costs alone, as suggested by Staff. First, transformer replacement costs have recently and significantly increased. In addition, for 2008, incremental funding is required based on specific expenses for transformer replacement cost obligations already incurred associated with the failure of 138Kv Jamaica Transformer #4 and 345Kv Dunwoodie Reactor #R1, as well as allowing for future failures based on past performance of the transformer fleet. The funding increase specified in the preliminary update filed in support of this program in August 2007 is also required to support the purchase of additional spare transformers to ensure adequate spares are available to respond to future failure scenarios.

Q. What has led to the increased costs in this program?

A. As discussed above, the re-evaluation of the adequacy of the current spares inventory was conducted due to recent experience with the significant increase in lead times for procuring transformers combined with a re-analysis of transformer failure probabilities prompted by the failures of Rainey Substation transformers 7W and 8W in close succession between December 2006 and mid-April 2007. The analysis was performed immediately thereafter and considered the following factors: historical failure data (by class), number of in-service units, replacement time, and number of spare units. The goal of the analysis was to identify additional spares that would be required to bring our confidence level that a spare transformer will be available in the event of a transformer failure to a point greater than 90 percent. This analysis showed that the number of spares for each of the following classes needed to be increased to meet this goal:

- 65 MVA transformer class - Increase Spare program by two.
- 234 MVA transformer class- Increase Spare program by two.
- 300 MVA phase angle regulator (PAR) class - Increase Spare program by two.
- 138Kv series reactor class - Increase Spare program by one.

MARK FOR IDENTIFICATION AS EXHIBIT ___(IIP-10)

Q. Please describe EXHIBIT ___(IIP-10)

A. EXHIBIT ___(IIP-10) is the Spare Transformer Probability Analysis that we discussed above.

Q. What would be the result of Staff's proposed reductions in this program?

A. Reductions in the requested increases to the program will reduce our confidence level in our Spare Transformer Program below the 90 percent expectation that we targeted in the probability analysis. This will result in increased risk of not having an immediately available spare in the event that one of the in-service transformers of a particular class fails.

Q. What will you discuss next?

A. Next, we will discuss Staff's recommendation to reduce funding to key Public Safety & Environmental Programs.

Q. Please continue.

A. First, we will discuss our Oil Minder program, followed by additional key programs: Vented Manhole Covers; Street Light Transformer; Pumping Plant Improvement; and Environmental Risk.

Q. What is the impact of Staff's proposed reduction to the Oil Minder program at page 45?

A. The funding reduction will result in an installation target of 250 units instead of the 300 units that were included in the rate case submission. This will increase the length of time to complete this program that is intended to ensure the environmental integrity of our vaults by reducing the risk of oil entering the municipal sewer system.

Q. Do you have any comments regarding Staff's testimony on the Vented Manhole Cover program funding recommendation?

A. Yes. Replacing solid manhole covers with vented covers allows ventilation of combustible gases that will mitigate the severity of manhole events. Staff's deferral of the Company's funding level will slow the replacement of both standard and non-standard covers by one year when the goal is to expeditiously replace these covers and improve public safety.

Q. Do you have any comments regarding Staff's testimony on the Street Light Isolation Transformer Program?

A. Yes. The Company proposes to install these units in the base of street lights on a four year plan, which is expected to eliminate approximately 78 percent of the stray voltage conditions. While Staff found this program to be justified, and recommended that the Company's proposed funding be made available, Staff recommends a clarification that the Company be solely responsible to install and maintain these transformers.

The Company does not believe that it should be held responsible for the maintenance of the isolation transformers. We believe that requiring the Company to shoulder maintenance costs for the transformers located inside City owned street lights poses an unnecessary burden on our ratepayers and would lead to delays in troubleshooting and repairing lamps from avoidable work handoffs between the Company and NYCDOT.

Q. Are there any other Environmental programs that Staff recommended reduced funding that you would like to discuss?

A. Yes. On page 44 of Staff's Infrastructure Panel testimony, Staff states that under the Environmental category, actual expenditures were not aligned with budgeted amounts between

2004 and 2006. Staff proposes decreasing the Pumping Plant Improvement program to $5 million from the $8.5 million proposed, and decreasing the Environmental Risk program to $2 million from the $3.5 million proposed. This represents a total decrease in the Environmental category of $5 million/year.

Q. Do you agree with Staff's proposed reductions?

A. No. A review of the data provided by the Company in response to Staff-466 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 between budgeted and actual expenditures of $727,000 represents an average difference of only 2 percent, or $243,000 per year, over the 3 year period. Thus, 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.

Q. How does the Company justify its proposed funding levels?

A. The proposed funding levels for the Environmental category during the proposed rate years represent an increase over past expenditures on average of $2.2 million per year, which is needed to complete the previously identified projects that will reduce the risk and mitigate the consequences associated with events that could impact the environment or the public. Program funding would also be used to address emergent environmental upgrades as they are identified. For example, recent transformer failures at the Rainey Substation have identified the need to further upgrade environmental controls and implement modifications that will further enhance risk mitigation at this location. In addition, funding in this category will support the following planned pumping plant and skid replacements:

• Corona #1 plant	$2,950,000
• W49th St. 1&2	$1,600,000
• Hudson Ave. 5&6	$1,600,000
• E13th St. 1&2	$1,800,000
• Astoria West 7&8	$3,400,000
• Queensbridge 1&2	$3,400,000
• Harrison 1	$160,000
• Sprainbrook 2	$160,000
• Dunwoodie 2	$160,000

Funding for other aspects of the Pumping Plant Improvement program include installing variable frequency drives and PLC control upgrades on Feeders 45, 46, 61, 62, 63, M54, and M55 at a cost of approximately $1,000,000 per feeder. Cooling plant upgrades will be performed at E13th St., Farragut, Rainey, and Gowanus at a cost of approximately $200,000 per plant. Leak detection system improvements, alarm panel upgrades, and pump house connectivity and remote monitoring improvements are also planned. Lastly, funding under the PURS Supervisory Control and Data Acquisition program will support replacement of the obsolete and unreliable Moore analog communication system for Feeders M51 and M52. Thus maintaining the requested level of funding for the Environmental category will ensure that previously identified and emergent environmental projects, as well as important dielectric system improvements, are addressed in a timely manner, thereby mitigating the risk and consequences of environmental events and ensuring continued safe and reliable operation.

The Company has provided detail on the planned projects for each of the Environmental programs in response to Staff-351 (Environmental Risk), Staff-422 (Pumping Plant Improvement), and Staff-423 (PURS Supervisory Control and Data Acquisition) which explain the scope of proposed work and the cash flow requirements. The extensive amount of proposed work clearly indicates the need, and provides sufficient justification for, the requested funding levels of these programs.

MARK FOR IDENTIFICATION AS EXHIBIT ___(IIP-11)

Q. Please describe EXHIBIT ___(IIP-11).

A. EXHIBIT ___(IIP-11) consists of Con Edison's responses to Staff Data Requests 351, 422, and 423 that we discussed above.

Q. What will you address next?

A. Next, we will discuss projects in the category of Storm Hardening and Response addressing Staff's recommended reductions. These programs include:

- C Truss Program
- Autoloop Reliability
- #4, #6 Self Supporting Wire
- 3-Phase Gang Switch Replacement
- Rear-Lot Pole Eliminations
- Enhanced 4kV Grid Monitoring
- 4kV UG Reliability
- Transformer Purchase

Q. Please continue.

A. Starting with the C-Truss Program, on pages 46 and 47 of the Staff testimony, Staff recommends a funding reduction from $1.7 million to $1.3 million on 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." The Company conducted the funding analysis based on a 7 percent rejection rate for poles. The 7 percent rejection rate used in the calculations is from an Engineering study conducted in 2003 on Osmose work performed from 1992-2002.

Additionally, Staff calculated its recommended reduction based on the Company capital expenditure for 2006 of $734,000. The expenditures provided by the Company for 2006 ($734,000) accounted only for capital expenditures from C-truss work. The proposed Capital funding of $1.7 million, however, is composed of two parts, 1) the C-trussing of an estimated 7 percent population, and 2) the capital portion for replacing approximately 1 percent of the inspected poles due to rejection that could not be corrected though C-trussing. The Company did not provide historical data that included pole replacement because the Company's work management system did not track separately the pole replacements due to Osmose inspections. The 1 percent pole replacement rate used to estimate funding was derived from the Osmose inspection of Queens in 2004. The 2004 Queens Osmose inspection was conducted on 8841 poles, with 117 of them being determined to be reject, non-restorable poles, a rejection rate of 1.3 percent.

Q. Please continue.

A. On page 47 of the Staff's testimony, Staff recommends a reduction of funding for the Autoloop Reliability program of $1.9 million. The purpose of this project was to address load growth on the affected autoloops and remain in compliance with EO-2066 and EO-2067. According to Section 5 of EO-2066 and section 7 of EO-2067, a Type II auto-loop should be installed if normal and emergency loads are 3.0 MVA and 6.0 MVA, respectively, and a Type III auto-loop should be installed if the normal and emergency loads are 6.0 MVA and 12.0 MVA, respectively. Additionally, section 6 of EO-2067 outlines feeder capacity and reliability considerations, requiring loads of no more than 3.0 MVA between reclosers. By reducing the funding to the program according to Staff's recommendation, Auto-loops that have or are developing loads greater than allowed by the current specifications will not be addressed, thereby falling out of compliance with specification and jeopardizing service reliability to the customer.

Q. Please continue.

A. On page 48 of the Staff testimony, Staff recommends a $1.11 million reduction in funding for the #4, #6, Self Supporting Wire Program. The fact is that the funding request by the Company is a conservative estimate given that load growth on the overhead feeders result in the larger branches of the feeder becoming overloaded first, with the radial spurs becoming the last to experience overload. Likewise, the reconductoring is planned proportional to the anticipated growth with a front loaded schedule to reconductor the larger main runs first.

In addition, the estimated cable footage was derived off of only the primary 4kV and 13kV conductors (3 conductors per span), but does not take into account the system neutral that should be at equal or greater capacity to the primary conductors. The result is a possible increase of up to 33 percent to the total reconductoring footage.

Finally, the cost estimate of $11.46/ ft is for 1/0 Aluminum, the smallest and least expensive cable. 2/0 Cu, 4/0 Al, and 477Al are the other predominate reconductoring cable sizes used. Accordingly, funding reduction to this program will unjustifiably lengthen the duration of the program.

Q. What will you discuss next?

A. We will rebut the proposed reduction to the 3-Phase Gang Switch program.

Q. Please continue.

A. On page 48 of the Staff testimony, Staff based a $100,000 reduction to the 3-Phase Gang Switch program on estimated historic replacement of gang switches. Additionally, Staff incorrectly states that the number of switches that actually required replacement is not consistent with the Company's estimated 20 percent replacement. The 20 percent figure was derived as a conservative estimate based on a recent inspection of approximately 100 gang switches in Brooklyn-Queens that yielded closer to a 35 percent follow-up maintenance or repair rate. Additionally, the estimated 20 percent rate of replacement is for a pro-active approach to replacement of switches going forward.

Q. Please continue.

A. Next, we will discuss the impact of Staff's proposed reductions to the Rear-Lot Pole Elimination Program.

Q. Please continue.

A. On page 48 of the Staff testimony, Staff dismissed the importance of the Rear-Lot Pole elimination program by deeming the program to be "non-essential," and therefore recommended a reduction of 50 percent to the funding of the program. The Company believes the program to be essential due to the following:

a) A dramatic increase in load and failure to the rear-lot secondary; with a limited ability to reinforce from a secondary or tertiary location.

b) Repair of failure in the Rear-Lot secondary has required reconductoring of multiple spans. Company expenditures for repair and upgrade of an obsolete system are not cost effective.

c) Safety concerns for Company employees entering limited access rear-lots. The Company's emergency department dispatches single man crews for Overhead trouble tickets. The emergency troubleshooter is required to traverse overgrown conditions, and limited illuminations in an attempt to make repairs.

d) The rate of construction throughout the Company's service territory has resulted in some rear-lot secondary's reaching capacity without an ability to perform a conductor upgrade.

Additionally, the 50 percent reduction recommended by Staff would, if continued, stretch the program from 20 years to 40 years, adding further strain on an already undersized system.

Q. What will you discuss next?

A. Next, we will discuss the Enhanced 4 kV Grid Monitoring program.

Q. What is your response to Staff's testimony at pages 49-50 regarding reductions in the Enhanced 4kV Grid Monitoring program?

A. There is more than a sufficient basis for the Company's proposed funding.

For year 2007, the received quote and cost from Square D / Schneider Electric for the initial 5 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 from Square D / Schneider Electric is $26,500 per station. Estimated cost for installation labor, overheads, and contingency per station is $15,350, yielding a total cost per Unit Substation of $41,850. Spreading the remaining stations over the period 2008 through 2011 yields:

Year	# Stations	Cost per Station	Total
2007	5	$50,000	$250,000
2008	35	$41,850	$1,465,000
2009	60	$41,850	$2,511,000
2010	85	$41,850	$3,557,000
2011	55	$41,850	$2,302,000
Totals	240	-	$10,100,000

Staff's proposed reduction will prevent the Company from deploying this technology in all our 4kV Unit Substations by the end of 2011.

Q. Do you have comments on Staff's reductions regarding any other programs?

A. Yes, we disagree with Staff's adjustment for the 4kv UG Reliability Program at page 50. Riser failures experienced over the last five years averaged 23.4 annually. With 743 in-service risers on the system, the failure rate is 3.15 percent per year. Failures are the result of cable, termination and joint failures. Repairs are generally made when possible, and cable is replaced only when necessary.

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. If so equipped, approximately 50 percent of the customers on the feeder are interrupted. Risers are critical infrastructure, and their failures affect 33,000 customers annually.

Our proposal is to replace the cable on risers that have previously failed and renewing risers that fail in the future by replacing all cable. The proposed program would include researching the root cause of the cable joint and termination failures and would begin a plan to replace poor performing cable and equipment.

Cable replacement necessary to renew a riser requires that three cable sections be replaced. These are the sections from the breaker cubicle within the substation to the substation manhole, the substation manhole to the street box, and from the street box up the riser pole. The average cost to replace a cable section within a riser is $14,000, which makes the cost to replace the three cable sections that make up a riser $42,000.

At $42,000 per riser, the cost to renew the 23.4 risers that fail annually is $983,000 per year. In addition to renewing those risers that fail, it is proposed to accelerate riser replacements by adding an additional 7.6 risers annually, increasing to 31 per year the number of risers that will be replaced. Setting the program length to 15 years will result in renewing 62 percent of the in service risers.

The cost for the additional 7.6 risers is estimated at $319,200 annually, making the total cost to renew failed risers and accelerate riser replacements $1,302,000 per year.

Q. What will you address next?

A. Next, we will discuss the reduction of the ED2 purchase of transformers and other equipment.

Q. Please continue.

A. Staff's proposal at page 51 to reduce the funding based on very limited data for lack of a better forecasting basis is ill-advised given that having sufficient replacement equipment is essential for our response to emergencies and the ability to maintain electric service to our customers during emergencies.

Q. What will you address next?

A. Next, we will discuss key programs within our Miscellaneous Components category of our capital programs.

Q. Please continue.

A. We will explain updates to our initial testimony as well as provide rebuttal to Staff's proposed reductions to funding levels. Specifically, historical expenditure levels do not accurately reflect the need or expenses required to maintain equipment and/or monitoring systems. The first program that we will discuss, Category Alarms, is an example of upgrading the aging obsolete alarm systems on the system. The problems associated with these systems include the failure of the annunciator/alarm cards, failure of power supplies, and grounded alarm cabling. The program calls for the replacement of these systems with computer microprocessor based systems. A recent survey all of the alarm panels in existing substations found a number of these panels and/or overall systems to be difficult to maintain due to lack of parts. Therefore the replacement program is being accelerated from two replacements per year to four per year. Replacing the units on a scheduled basis rather than on an emergency basis reduces the replacement cost and allows for a favorable scheduling of the replacement.

Q. Does the Company agree with Staff's recommendation at pages 30-31 to reduce funding to this program?

A. No. The increased funding requested addresses both the increase in the number of units per year we plan to replace, as well as the significant cost increase associated with replacing entire alarm panel systems. Included in this program request is the replacement of the E. 13th Street alarm panel system. This system incorporates 345kV and 138kV equipment at the East River Complex, and will require extensive conduit and fiber optic installations. In addition, a switching station, by design, has a higher number of alarm points than an area substation. We have identified 3 panels for near term replacement--Brownsville, Goethals and Washington Street. In the longer term, we have identified 11 alarm panels that have frequent repair issues or are difficult to repair/maintain due to parts availability. These panels will be prioritized and replaced under this program.

Q. What will you discuss next?

A. Next, we will discuss the proposed elimination of our Facility Upgrade program by Staff. Staff's testimony, states at pages 32-33 that the Facility Improvement program is not justified and should be eliminated on the basis of historical expenditures and that this program appears to be redundant to the Company's Small Capital program. In addition, Staff incorrectly states that no historical spending or budgeting data for the Facility Improvement program has been provided. Staff also states that the high voltage test set project for Parkchester would more appropriately fit under the new High Voltage Test Set Program, and that the fire protection system upgrades at Dunwoodie should be included under Transmission capital, not under Substation Facility Improvement.

Q. Does the Company agree with Staff's testimony regarding the Facility Improvement Program?

A. No. The Company's Facility Improvement program funds a wide range of important large scale facility upgrades. Notably, this program provides funding to establish permanent work locations for employees working out of temporary office trailers. It also funds other large scale projects such as structural improvements to façades, foundations, retaining walls, lifts and platforms, floors, heating and ventilation, lighting, and plumbing. Additionally, this program funds work such as large scale drainage modifications, paving and fencing.

The scope of the Facilities Upgrade program is intentionally broad and encompassing and is required to fund larger scale projects not covered by other capital programs. Staff contends that candidate projects for this program such as those related to fire protection system improvements or high voltage test set facilities are redundant since there are other capital programs, entitled Fire Protection Program and High Voltage Test Set Replacements, to address these issues. Moreover, Staff states that the Facility Improvement program candidate projects could be funded by the Small Capital program. In essence, Staff takes issue with how the Facility Improvement projects have been categorized, not with their validity. However, none of the identified Facility Improvement projects are redundant with the Company's Small Capital Program or any other defined scope capital program. The Facility Improvement project list provided in response to DPS-489 clearly demonstrates that the projects are not redundant and are not funded through any other capital program request.

Included in the list of candidate projects are projects to establish permanent work locations for Substation personnel that currently work in temporary office trailers at various work locations. Projects funded under this program will facilitate transition of personnel from temporary facilities to permanent facilities. Housing permanent personnel in temporary trailers is not an acceptable solution due to municipal regulation, the poor working environment and safety issues associated with long term use of temporary trailers. Approximately 85 permanent Substations personnel at 15 different locations are currently housed in temporary trailers.

Funding is also requested under this program to make building modifications to accommodate the addition of a high voltage test set at the Parkchester Substation. Contrary to Staff's position, building modifications are clearly beyond the scope of the proposed High Voltage Test Set program. While it may have been possible to categorize this work to fall under the High Voltage Test Set program, this work was instead categorized as facility improvement, and the funding to perform this work therefore was not allocated to the High Voltage Test Set program. The Company response to Staff-145 clearly delineates that the funds for the High Voltage Test Set program are meant for the purchase of and/or replacement of equipment and not 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 only provides funding of $500,000/year for the purchase of 3 DC high voltage test sets. Thus, utilizing the High Voltage Test Set program budget for the Parkchester facility project would prevent or delay the needed replacement of 3 DC high voltage test sets at other locations. The Dunwoodie Station fire protection system water supply line and deluge house replacement is another example of a project that could have been categorized under a different program, in this case the Fire Protection program, but is proposed to be funded as a substation facility improvement project. 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 NYC codes and regulations. The program is funded at $500,000/year to support the completion of modifications at 6 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 this program.

While the scopes of the Small Capital and Facility Improvement programs are similar, each program 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-145. Each of the 37 projects identified in this list is estimated to be less than $500,000 to complete. In comparison, the Facility Improvement project list provided in Staff-489 identifies over 30 projects each of which is estimated to cost $500,000 or more. None of the projects listed are redundant with the

Company's Small Capital Program or any other defined scope capital program.

Since our response to Staff-489 response was provided, we have identified additional candidate projects that would be funded under this program and have updated the list of current candidate projects to be funded under the Facility Upgrade program. In addition to the projects listed, there are still a number of other candidate projects being considered for inclusion in this program that do not yet have fully developed job scopes and estimates, have not been prioritized, and are therefore not included in the updated list. These projects fall into the categories of drainage, foundation, and wall improvements, HVAC and lighting upgrades. We also identified several projects to be deleted from the candidate listing. These are either duplicate projects, have been identified in another program, or have been shifted to another program due to revised prioritization/cost estimate. There is a constantly evolving list of candidate projects, as issues are identified in the field, and solutions developed by Engineering.

Historical data for the Facility Improvement program dating back to 2002 has been provided in response to Staff-125 and the actual amount spent in each year has exceeded the budgeted amount demonstrating the need to continue funding this program. The present candidate project list provided to Staff lists over $30,000,000 of planned and proposed projects for the next 3 years to correct and upgrade numerous age-related structural and facility issues, as well as transition personnel from temporary trailers to permanent facilities in order to ensure safe and reliable operation of the substations. The Company recognizes it would not be reasonable to take on all of these facility improvement projects within the 2008-2010 periods and intends to prioritize these projects to fit within the established level of $6,000,000 per year in funding as an ongoing program. 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.

MARK FOR IDENTIFICATION AS EXHIBIT ___(IIP-12)

Q. Please describe EXHIBIT ___(IIP-12).

A. EXHIBIT ___(IIP-12) consists of Con Edison's responses to Staff Data Requests 125, 145, and 489 that we discussed above.

Q. What will you discuss next?

A. Next, we will discuss Staff's recommended reduction to our SOCCS - RTU Replacement program discussed at page 31. The Company disagrees with Staff's recommended reductions based on historical expenditure levels. The historical expenditure levels do not accurately reflect the need or expenses associated with the future requirements of this program. The RTU is the key link for transmitting critical operational data between each transmission substation and the Energy Control Center. Each RTU continuously monitors and controls each transmission station circuit breaker, motorized disconnect switch, phase angle regulator, transformer and telemetering of each feeder. The last time the RTU's were installed was in the late seventies and early 1980's when Con Edison installed the Boeing SOCCS system.

These RTUs are now reaching the end of their useful life. Spare parts are no longer readily available and as a result the ability to maintain these critical components is compromised. These components now represent the weakest link in the communication chain between the Energy Control Center, the new Alternate Energy Control Center and the transmission substations. For this reason the Company plans to replace these units on an expedited basis over the next 3 years at all the Company's transmission stations.

In addition to resolving obsolescence and reliability issues, replacement of the existing RTU's with new technology will support communication with multiple systems and will provide system expansion capability. The existing RTU's work on an old protocol called BE-TAC. This BE-TAC communication protocol is not directly compatible with the communication protocols used with the new Energy Management System ("EMS"). The existing RTU communication protocols limit the speed of data transmission to 1200-baud modems and prohibit communication with other advanced substation devices. In the interim, these in-service RTUs have been outfitted with modified communication kits that will allow them to communicate with the new EMS as well as multiple masters, such as the Energy Control Center ("ECC") and the Alternate Energy Control Center ("AECC"). Without a full replacement of all aging RTUs, the supervisory and control capabilities of these substations cannot be expanded. As a result, expansion of the new EMS will be encumbered delaying realization of its full capabilities.

Another key aspect of proceeding with the replacement of the existing RTU's as planned is improved system security. The selection of an open architectural communication protocol [DNP3.0] as the standard protocol for the system will support compliance with the NERC Cyber Security Standard.

Q. What is the Company's total funding request for this program and what does it cover?

A. The total funding requested for this program is $9 million for 2008-2010, which equates to approximately $235,000 per substation. The funding request covers the replacement of the RTU's at all 38 of Con Edison's Transmission Substations.

Q. Does this conclude your rebuttal testimony to Staff's proposal regarding the SOCCS - RTU Replacement program funding?

A. Yes. Next we will respond to Staff's proposal at pages 31-32 of a 50 percent cut to a program they agree is justified - the Substation Loss Contingency program.

Q. Please continue.

A. Staff states in their testimony on page 31 that this program is justified, however recommends reducing the program from $2.0 million to $1.0 million based on low historical expenditures. As described in response to Staff-489, this important program is geared toward preparing for the loss of any one of a number of selected transmission substations. Planning and procurement of spare equipment in advance of a substation loss will enable more rapid restoration of the electric system. To date, restoration plans have been developed for the individual loss of one of several 345 kV, 138 kV, or 69 kV transmission substations. As the Company's response to Staff-489 demonstrates, plans have now matured to the point that equipment and engineering packages required to support these contingency plans have been specifically identified. The requested funding of $2.0 million per year is necessary to procure the equipment and develop the engineering packages identified in our response to Staff-489. A reduction in funding will extend the time necessary to complete this important initiative.

Q. Does that conclude your rebuttal to Staff's reduction of the Substation Contingency program?

A. Yes. Next we will discuss Staff's proposed reductions to our Advanced Technology programs.

Q. Please continue.

A. The Company contests the reductions proposed by Staff at page 53 to the Secondary Visualization Model, SCADA System and the Electric Distribution Control Center Upgrade projects. The reasons for the reductions appear to be based arbitrarily on the basis of historical expenditures or on Staff's unsupported views as to whether the Company requires or can expend the amount requested to fulfill the program objectives. Staff's testimony concedes that the "programs are warranted and justified," but simply cuts the program based on historical spending.

Q. Please continue

A. First, We will discuss the Secondary Visualization Model ("SVM") Program. In our effort 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.

In order to effectively model the secondary network load flows it is imperative that the secondary network mapping data is accurate and fully connected. These first two steps ensure 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. We have developed automated processes to extract the mapping data and check for connectivity. Prior to initiating the remaining steps for a network all errors in the mapping data have to be resolved. 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 in the first year of the rate case. This is required to ensure that the remaining steps for secondary network model creation can proceed in parallel for the targeted networks each year.

This is the primary reason behind higher dollar allocation to the first year of the program. The additional resources to address all mapping issues are warranted, and taking the average of the proposed expenditures over the three year rate case period adversely impacts the progress of the program and the ability of the Company to timely complete all the secondary models.

Q. Are there any other technical systems that you'd like to discuss?

A. Yes. System Control and Data Acquisition ("SCADA") system program collects and permits control of the various distribution equipment. As discussed previously, system automation and technology enhancements and associated software and equipment upgrades are necessary for these systems. The SCADA system is the source of the information is collected and analyzed by sophisticated computer algorithms. The Company currently has one of the most extensive SCADA systems in place. However there are areas where the system requires improvement, such as 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. The system consists of 217 unit substations connected in a grid manner via 4kV cable that also distributes power to our customers along its length. With economic growth and expansion of residential areas in our service territory, the load growth on the 4kv grid along requires that the 4kv supply system be reinforced and modernized. Over the last decade remote monitoring and control of the system has been completed at the substation level. This SCADA system known as the USA system provides important information on station and feeder loads as well as several control functions from the Distribution Control Center. The USA system is a step change enhancement from the previous rudimentary and simple alarm systems technology. Hence at the station level the Company has completed the installation of the more modern USA system that now needs to be integrated and deployed at the feeder level, specifically at a critical location midway between two feeders at a sectionalizing point. Once again with future enhancements and upgrades in mind, the Company began phasing out the older vintage sectionalizing switches replacing them with state of the art KYLE solid state controlled switches. With foresight, the Company purchased and continues to purchase KYLE switches with remote communications and control capability. As these switches increase in numbers through emergency and planned replacements, the need to develop SCADA System for the 4kV system has increased. The modest request for $1.5 million is to begin the phasing in of the 4kV SCADA systems to take advantage of the complete capabilities of the KYLE switches.

Q. What were Staff's recommendations regarding the SCADA system?

A. Staff recommends at page 53 a $500,000 reduction to the program. Staff's proposed reduction is arbitrary and will preclude the Company from optimizing the technical features of its KYLE switches.

Q. Describe the Distribution Control Center Upgrade program.

A. The Distribution Control Center Upgrade program ("DCCU") updates the Company's electric Control Centers with current software and technology and improves their performance with new operating tools such as SVM, HUD and SCADA systems., The 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 date with current technology. The second contingency design of the Company's distribution system requires the use of technology for automated operations. The radial supplied areas of the overhead system require monitoring and control of several hundred sectionalizing devices. The Company as a whole maintains over 134,000 of remote monitoring points requiring computer technology, communications, system integration modules, hardware and software that are constantly evolving for speed, reliability and accuracy. In these later years, security concerns have further amplified the need for secure hardware and software in the control center environment where energy delivery operations are concentrated.

Q. Does the Company agree with Staff's proposal for this program?

A. No. Staff proposes at page 53 to reduce this program by $2.3 million. Once again Staff's justification for denial is based on historical spending; Staff fails to consider the consequences of not adequately supporting technology deployment in critical areas of power delivery systems. The Company disagrees with Staff's proposed $2.3 million reduction and believes the program funding for $5 million should be maintained.

Q. Does that conclude your rebuttal regarding Staff's proposed reductions in to the Advanced Technology projects?

A. Yes. Next we will discuss Staff's proposal to reduce the Company's Security Enhancement program by over 50 percent.

Q. Does the Company agree with Staff's testimony at pages 43-44 regarding the Company's security initiatives?

A. No. Prior to the rate year of 2008, Substation Operations security initiatives and expenditures were funded under a separate corporate responsibility budget line associated with the World Trade Center attack. The reason the historical expenditure level prior to the rate year at the departmental level appears to be minimal is that these expenditures were not in rates pending the outcome of Federal and/or insurance reimbursement. Of these expenditures, $333,700 was eligible for 75 percent reimbursement under HUD's Utility Restoration and Infrastructure Rebuilding Partial Action Plan S-2, (eligibility was defined as locations located or benefiting customers below Canal Street in Manhattan). In June 2007, the Company received reimbursement in the amount of $250,200. Starting with 2008, the funding responsibility will be reassigned to the individual departments.

Q. Are there any other reasons you disagree with Staff's testimony?

A. Yes. We likewise believe improving our security systems is of utmost importance. 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. In response to Staff-424 we provided a detail project schedule that outlines a reasonable approach to bring all of our substation facilities into compliance with our Security specification by the end of 2010. The requested funding is necessary to meet this schedule and a reduction of funding will delay completion of important security enhancements.

Actual historical expenditures associated with substations security projects compared to the Rate Case request is in-line with the Company's request:

2004	$ .5 million
2005	$1.2 million
2006	$2.9 million
2007	$3.0 million

Rate Case:

2008	$4.1 million
2009	$4.1 million
2010	$4.0 million

MARK FOR IDENTIFICATION AS EXHIBIT ___(IIP-13)

Q. Please describe EXHIBIT ___(IIP-13).

A. EXHIBIT ___(IIP-13) consists of Con Edison's response to Staff Data Request 424 that we discussed above.

Q. Does that conclude your rebuttal to Staff's testimony?

A. Yes, except for two general comments. First, as mentioned in several places above, Staff's proposed funding reductions for projects that it believes are fully justified, but have either experienced underspending (relative the budgets) in past years or lacked historical experience are without merit. The fact that the Company has not spent budgeted amounts in the past for a specific project or program, or has not budgeted any amount in the past for such project or program is not indicative of the amount that should be and will be spent in the future. Whatever justification there may be for a slippage adjustment when total expenditures are below budget -

which the Company has not experienced, there is no justification for a slippage adjustment to specific projects that are otherwise justified. In fact, there is no reason to believe that a project that has slipped in the past for reasons such as equipment delivery delays will continue to slip once the equipment is delivered. Nor is there reason to believe that a project or program will slip simply because it is a new project or program with no historical expenditure data.

Moreover, given Staff's recommendation that total T&D capital spending be reconciled and any underspending be deferred for ratepayer benefit, there is no reason to deny the Company the funding it requests for justified projects. If Staff is correct in its assessment that the Company may underspend, such underspending will be captured and returned to ratepayers.

Second, we fail to understand why Staff would recommend that underspending should be deferred for ratepayers' benefit without also recommending that overspending be deferred for later recovery by the Company. Estimates for specific projects and programs can turn out to be understated and new capital projects can become necessary. Absent the ability to defer such overspending, the Company would be forced to reduce spending on other projects that are justified whenever it needs additional funds for an underestimated or new project.

Q. Do you have any rebuttal testimony addressing other parties?

A. Yes. The Company would like to address general recommendations regarding capital and/or O&M expenditures in testimony submitted by the Consumer Protection Board ("CPB") witness Douglas Elfner, the New York Power Authority ("NYPA"), and the County of Westchester ("COW"). We will also address more specific recommendations regarding O&M expenditures made by CPB witnesses Helmuth W. Schultz, III and Donna M. DeRonne ("Schultz & DeRonne"). Additionally, we will address a recommendation by Astoria Generating witness Timothy Bush and testimony from Richard Koda on behalf of the Utility Workers Union of America, AFL-CIO, Local 1-2 ("Local 1-2").

Q. Does the Company agree with the general recommendations made by CPB witness Elfner, NYPA and COW for reductions in the Company's proposed capital and/or O&M expenditures?

A. No. Through its testimony and exhibits as well as the interrogatory responses included in Staff's exhibits, the Company has demonstrated the need for the projects and programs it proposes. The capital and/or O&M reductions proposed in testimony from the CPB (Elfner), NYPA, and COW are arbitrary and are unsupported by any analysis or assessment of the impact their proposals would have on any or all of the projects and programs the Company has proposed. The reductions proposed by these parties should, therefore, be rejected.

Q. How does the Company respond to the questions raised by CPB witnesses Schultz & DeRonne at page 42 regarding increased costs per repair for the underground inspection program?

A. The increase in cost per repair associated with the underground inspection program is due to the increased number of repairs directly related to the safety inspections and the increased number of inspections required to meet the Commission's Safety Standards issued in Case 04-M0159 requiring that all electric facilities be inspected within a 5 year period. In 2006, approximately 50 percent of inspections and repairs were completed during normal maintenance in order to effectively conduct these inspections. In the proposed rate plan period, inspections and associated repairs will be beyond the scope of normal maintenance work. Therefore, additional work will be required to complete the Commission's Safety Standard requirements, which accounts for the increase in costs.

Q. How many additional inspections is the Company required to conduct?

A. An incremental 50,000 inspections are required to meet the requirement of approximately 275,000 underground structures to be inspected. The remaining number of underground facilities must be inspected separately to ensure each discrete structure is inspected within the framework of the Commissions Safety Standards. There were no such programs in existence in 2004 because the Commission's Safety Standards were not issued until January 2005.

Q. How has the use of mobile testing detectors helped to reduce instances of shocks?

A. The decline in shocks to the public is a result of the Company's use of the mobile detectors. As the use of the vehicles increases, more stray voltage conditions are found. By finding more stray voltages the potential for stray voltage to be exposed to the public is reduced and the number of shocks declines.

Q. How does the Company address CPB's questions at page 47 regarding the number of miles covered by the mobile detectors?

A. There are several reasons why the vehicles cover only 20 miles per day. First, the vehicle must observe traffic signals and laws, which reduces the average speed of the vehicles, particularly in dense urban areas. Second, in the instance that a vehicle detects the presence of a stray voltage condition; the operators must park the vehicle, exit, and investigate the area to pinpoint the location of the stray voltage. Once the surface/structure with stray voltage has been identified, the operators of the vehicles must safeguard and remain at the location until a standby crew can relieve them of this duty.

Q. How does the Company address the increased cost in standby charges from 2006 to 2007?

A. The increased cost is a result of increased mobile testing, which has resulted in more stray voltage conditions found. As more stray voltage conditions are found, they must be guarded by site safety personnel, as required by the Commissions Safety Standards. Therefore, by finding more stray voltages, there is an increase in the use of standby personnel to ensure that the stray voltage conditions are safeguarded from the public until the issue can be mitigated.

Although the additional testing in 2007 has resulted in a reduction of shocks, it is evident that persistent scanning must continue to be performed despite improvements to the system, and that the overall cost for standby and repairs will still see an increase as the frequency of scans on the system increases.

Q. Do you have further rebuttal testimony addressing CPB?

A. Yes. Next, we would like to discuss CPB's testimony regarding the elimination of five Substations O&M programs identified in Company Exhibit IIP-3.

Q. Are there any assertions made by CPB witnesses Schultz & DeRonne with regard to the Substation O&M program that are factually incorrect?

A. On page 28 of their testimony, they state that the Company's incremental request of $11.028 million represents a 31 percent increase over the test year expenses of $35.245 million. Substation Operations actual expenses for the historical rate year were $89.181 million, not $35.245 million. Accordingly, the current incremental rate case program request of $11.028 million represents a 12.4 percent increase over the historical rate year, not a 31 percent increase. It should also be noted that $4.701 million a significant portion of the total $11.028 million request, is related to the future O&M requirements for new substation facilities - Mott Haven, Parkview, Rockview, Astor, Academy, York and Newtown. Thus, the Substation Operation O&M request identified on Exhibit IIP-3, exclusive of new facilities, represents a $6.327 million or a 7.1 percent increase.

Q. What recommendations does the CPB make with respect to reductions in Substation Operations O&M expenditures?

A. On page 30, CPB witnesses Schultz & DeRonne recommend a $3.737 million reduction to Substation Operations O&M. This proposed adjustment removes $592,000 for Labor and $3,145,000 for unsupported other costs. The affected programs are

Telecommunications, Advance Control Group, Cable Cooling Maintenance, Dynamic Feeder Rating System and Structural Integrity / Station Betterment.

Q. What was their rationale for these reductions?

A. The only rationale the CPB witnesses put forth for their recommendation to eliminate these programs is that they could not audit the basis for their estimated cost because the Company did not provide the supporting documents that CPB's witnesses deemed necessary. CPB claims that the Company's filing, supporting workpapers and discovery requests responses failed to provide sufficient details to support the requested expenses. CPB also states that the Company's filing lacks proper organization and cross referencing. Whether or not CPB's claims have merit, it is inappropriate for CPB to wait until its responsive testimony to raise such complaints and it is inappropriate for CPB to recommend that projects that may be necessary for reliability not be funded because CPB does not approve of the Company's presentation. Had CPB been interested in investigating the Company's proposed expenditures, it could have pressed the Company for additional details, or filed a Motion to Compel the Company to provide whatever data or details CPB deemed necessary for its review.

Q. Are there any practical constraints that inhibit the Company from responding as requested by these witnesses?

A. Yes. First, 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.

Q. Please comment on some of the Substation O&M programs recommended by CPB for elimination.

A. Yes. CPB has recommended the elimination of several Substation O&M programs. Elimination of these programs is neither justified nor reasonable and would negatively impact the Company's ability to improve performance as well as sustain and enhance reliability. Among the programs identified by the CPB for elimination are the following:

Dynamic Feeder Rating:

This is a new program that provides for vendors to maintain and repair Dynamic Feeder Rating equipment coming off warranty. The Dynamic Feeder Rating System allows additional capacity on existing transmission feeders to be utilized which is a significant benefit for system transmission capacity and reliability. The supporting detail for the maintenance costs associated with this system was previously provided in the Company's response to Staff-219, which was also provided to CPB. Those details identified the specific feeders where the installed dynamic feeder rating equipment will no longer be covered by warranty. The need to expend O&M funds on a service contract to support equipment previously maintained under warranty is a new incremental expense. Cost estimates provided were based on vendor costs to maintain similar equipment associated with the pipe-type dielectric oil filled feeders. Elimination of this program would adversely affect system transmission capacity and reliability.

Advanced Control Group:

This is a new program requiring dedicated Company personnel to develop and maintain the expertise to support significant advances in technology now being deployed across the system.

The total request consists of $592,000 for Company labor and $200,000 for vendor training and minor materials. These technologies involve advanced computer and communication systems. Existing Company personnel are not well versed in these applications. They are required for the reliable operation of our system and must be supported. This group is meant to provide internal company expertise in this advancing area of technology so we can take full and productive use of it. Elimination of this program would result in the need for the Company to rely on limited and costly vendor support and would significantly inhibit the Company's ability to develop the infrastructure and the in-house technical expertise to adequately support and maintain these hi-tech systems.

Q. Does the Company agree with CPB's testimony regarding Facilities Betterment projects?

A. No. Concrete pads and footings, trough covers, substation walls and equipment protective coatings will be addressed as part of this on-going program. Required funding to support this program is $2 million per year. This program proactively addresses long term facility and equipment degradation caused by exposure to the elements as well as normal wear over time. This restoration work is considered O&M and is beyond the scope included in the base O&M budget. Elimination of this program as the CPB has recommended would result in continued degradation of station facilities as well as more expensive and costly repairs in the future.

Q. Does the Company agree with CPB's testimony regarding the Company's telecommunications programs?

A. No. The main component of the Incremental Telecommunications request is based on a new leased service agreement provided by Verizon that provides data connectivity, similar to an internal LAN Network. The funding requirement represents cost for the installation of the fiber lines, Transparent LAN System ("TLS") service cost and Digital System Protection circuit cost. Approximately $290,000 of the $480,000 being requested is as a result of TLS. The balance of the request is due to the increase in telecommunication needs of the department to accommodate increased demands for networks, circuits and devices, much of it associated with new facilities. There is a signed agreement between Verizon and Consolidated Edison for the implementation of TLS. The requested incremental O&M funding is required for the Substations organization to fund the contracted services and other incremental telecommunication costs.

Q. Does the Company agree with CPB's testimony regarding costs associated with the 59th Street Cable Cooling plant?

A. No. As discussed in the Company's work papers, the frequency of required desilting and heat exchanger cleaning is increasing at the 59th Street Cable Cooling plant. Based on having to conduct a desilting operation every 18 months and 1-2 additional heat exchanger cleanings per year, the annualized incremental cost is projected as follows:

- Desilting Cost - Assumes an occurrence every 18 months versus the previous frequency of once every 3 years at $400k per occurrence or $270k on an annualized basis.

- Additional Heat Exchanger Cleaning Costs - Assumes 1-2 additional cleanings per year or $20k to $40k per year.

- Total incremental cost estimate for desilting and additional heat exchanger cleaning - $300k per year.

This program is for an incremental increase to the base cost of maintaining the cable cooling system located at the 59th St Generating Station. Routine maintenance work activities include system pump repairs, heat exchanger cleanings, water treatment, desilting, and miscellaneous.

Q. Please describe the CPB's position regarding the Bird Discourager Program.

A. In an interrogatory request, CPB asked why the Bird Discourager Program was not capitalized. The Company responded by providing CPB with its accounting guidelines and procedures and also stated that it was industry standard to account for this type of cost as expense because, by itself, it is not a depreciable unit of property. Based on its testimony, CPB believes that the Company is trying to accelerate cost recovery of this program.

CPB is wrong. Several outages on 345kv feeders (namely W93, W97 and W98) which support the F and P lines occurred because of bird activity, causing phase to ground faults at transmission structures in Buchanan and Courtland. Installation of these bird discouragers will prevent the bird activity by increasing the air gap between conductors and the birds. These feeders are critical to the electric system and outages to these feeders can put the transmission system at risk. The purpose of this program is solely to discourage birds from roosting at certain locations on the transmission poles, which we believe has caused outages in the past. For this program to be ruled capital, as CPB is recommending, the Company would have to remove the existing poles and install the bird discouragers together with new poles. This option is not cost effective because the cost to replace a pole by far outweighs attaching the discouragers to existing poles. The Company believes that installing these discouragers is not only a sound decision from a business standpoint, but also from a reliability and environmental standpoint.

Q. Does the Company agree with CPB's testimony regarding the Manhole Refurbishment Program?

A. No. CPB states in its testimony that the Company did not provide a reason for the increase in the unit cost of refurbishing manholes. CPB further stated in its testimony that the Company's estimate for the rate year averaged out to $13,333 per manhole, an increase of $4,735 per manhole when compared to the unit cost of $8,598 in 2006. However, the number of manholes used by CPB to compute the unit cost for the rate year is incorrect. The number of manholes to be refurbished during the rate year is 108 manholes at a unit cost of $11,111, as stated in the Company's program change form. Therefore the increase in cost per manhole is actually $2,513, and not $4,735 as calculated by CPB.

The increase in units from 86 in the historic year to 108 in the rate year is due to the Company being proactive in conducting more repairs on the aging system in an effort to reduce the number of leaks and mitigate the environmental impact of the leaks. Feeder and manhole selection is determined by an analysis of historical feeder leaks, feeder aging and overall potential environmental impact. This targeted proactive approach has enabled the Company to identify extensive localized feeder pipe corrosion. Thus, unit cost has increased in order to repair identified corrosion. The work includes the removal of all tape coating and mastic on feeder pipes, joint sleeves, valves and oil lines and performing a visual inspection a wall thickness check on corrosion areas and conducting associated repairs such as wire brushing, grinding and recoating. Repair scope will expand if the facilities within the manhole are in poor condition and integrity is compromised or the corrosion has propagated to the manhole wall penetration. For repairs of compromised pipe within the manhole, Company field forces fabricate steel barrels and weld over the corrosion areas as required. After repairs are completed, new tape coating and mastic is applied to the pipes, sleeves and valves in the manhole.

If corrosion is more extensive and has propagated to the pipe penetrations at the manhole's concrete end walls, then the concrete wall would be removed. This operation requires the area outside of the exterior wall of the manhole to be excavated to provide for full access to the corrosion area and the concrete wall removed to facilitate repairs. Upon completion of this work, a complete wall thickness assessment can be performed and repairs to the corrosion areas as described above can be implemented. Once the assessment and repairs are complete, the manhole wall, excavation and street surface will be restored.

Q. Are there any other proposals regarding O&M programs that you wish to rebut?

A. Yes, the testimony by CPB witnesses Schultz & DeRonne pertaining to the Five Year Overhead ("OH") Inspection Program. The OH inspection of all distribution overhead wood poles was conducted in 2005 as soon as the PSC Order, Case 04-M-0159 was officially issued in January 2005. The cost justification of $5.443 million in the rate year is based on cost incurred in the test year and is based on five years of inspections.

Q. Please comment on CPB's testimony regarding the Company's Annual Stray Voltage Program.

A. The Annual Stray Voltage Program began in 2005 when the Public Service Commission mandated an annual testing program in accordance its Safety Standards. The costs associated directly with this program began in 2005; therefore, the costs incurred in 2004 did not affect this program as referred to in CPB's testimony. The incremental costs are based on the fact that testing costs will rise due to increased contractor costs when the 2-year contract expires, as well as higher level of repair costs as more stray voltages are found

A reduction in the request will severely limit stray voltage testing and will impact the Company's ability to meet the PSC Safety Standards. It will also impact the confidence of the test results by limiting the oversight of contractors.

Q. Astoria Generating Company witness Timothy Bush (pp.7-9) states that Con Edison is considering DSM to provide load relief within the East 13th Street load pocket but if the Company is unable to achieve the required DSM levels system needs will not be met. Please comment on Mr. Bush's assertion.

A. Mr. Bush is referring to the replacement of support for the East 13th Street load pocket once the Poletti Generating Station is retired in 2010. Con Edison has performed load modeling studies to determine a conservative estimate for the amount of DSM load relief required for the delay of a transmission solution (reconfiguration of feeders Q35 L & M to connect one or both of the Astoria switching stations to the East 13th Street switching station). The cumulative amounts of DSM relief required for the East 13th Street load pocket are as follows:

2010:	46 MW
2011:	56 MW
2012:	67 MW

Based on the conditions anticipated for the years in question, Con Edison has determined that these DSM reductions would be sufficient to maintain transmission flows below thermal ratings and voltage profiles within acceptable ranges according to second contingency design criteria. If the required amount of DSM should not be obtained, we disagree that system needs would not be met. In that event, Con Edison would rely on several strategies of mitigation. These may include, but are not limited to: incorporation of distributed generation at area stations and customer sites, and utilization of extended ratings for up to 300 hours.

Q. Local 1-2 makes recommendations regarding the use of mutual assistance labor, contractor labor, studies regarding contractor labor and the security associated with contractor labor. Please comment.

A. Mr. Koda's allegations regarding the Company's longstanding procedures and practices applicable to the use of contract labor are unsubstantiated. The Company uses an appropriate and changing mix of skill contract labor in discharging its responsibilities for maintaining its system in a cost-effective manner. This ever changing labor mix is dependent on the scope of planned construction endeavors. The Union's transparent attempt to limit the Company's ability to draw on these valuable resources, to the benefit of the Company's customers, is no more than a self-serving attempt to increase the Company's reliance on Local 1-2 personnel. Overall, the adoption of additional Local 1-2 personnel would tend to limit the labor skill flexibility required in achieving efficiencies. Moreover, when the Company uses outside contractors, the Company's terms and conditions for construction contracts establish appropriate guidelines to which the contractors are subject that consider safety and environmental issues, among many others.

Q. Does the Staff Infrastructure Panel recommend that the Company provide any reports relating to spending on infrastructure?

A. Yes. Staff states (p. 11) "Con Edison should be required to file with Staff a quarterly report providing detailed information comparing, by project, actual construction progress to Con Edison's projected schedules and actual expenditures with rate year allowances. Justification should be provided for any discrepancies on a project by project basis, as well as an aggregate for all projects."

Q. Does Staff give any justification for this recommendation?

A. They simply state that "the impact of the Company's proposed T&D budget on rates demonstrates the need to ensure that the Company is held accountable for its rate allowance for electric infrastructure improvements."

Q. Do you agree?

A. No. Each January, the Company currently provides Staff with an annual report comparing construction expenditures to the prior years forecast and explains any variation greater than 15%. In addition, Company personnel meet quarterly with Staff to discuss the current construction program. To date, we know of no complaint regarding the report provided by the Company nor has Staff requested any additional meetings, i.e., more frequently than quarterly. Therefore, we believe that the current reporting requirements are more than adequate.

Q. Do you have any comments as to the timing of the reports?

A. Project schedules do not generally change as frequently as quarterly and a report from quarter to quarter would not be useful.

Q. What about the request that every deviation in a project be accounted for?

A. Providing an explanation for spending deviations on a project-by-project basis quarterly is unreasonable and impracticable and of little or no value. Staff would seemingly require that a $5,000 change on a $50,000 project, or over spending on a project by as little as $1,000 in one quarter, be explained. Among other things, Staff does not consider that there is a timing variation regarding accounts receivable v. accounts payable beyond a three-month cycle and that their recommendation would require an increase in the number of resources and system development for such an undertaking. The additional Company resources that would be required to meet these new obligations have not been identified or quantified by Staff, nor has Staff explained whether the value of such reports would justify this expense. Furthermore, in the Company's view, there are no project-specific rate allowances. For all of the foregoing reasons, this Staff recommendation should be rejected.

Q. Does Staff also seek a reconciliation of expenditures?

A. Yes. Staff states (p. 11) that "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."

Q. Please comment on this proposal.

A. 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. Moreover, it is patently inconsistent with other Staff positions that reconciliations mechanisms are generally not appropriate for a one year rate plan. If and to the extent the Commission determines that such costs should be reconciled, such a mechanism must reasonably address the nature of the Company's capital expenditure program in a fair and even-handed manner. Moreover, Mr. Rasmussen's initial testimony (pp. 14-15) stated that "should the Commission establish rates in this proceeding that reflect less than the Company's forecasted T&D capital expenditures, the existing true-up mechanism should be continued."

Q. Are the "mechanics" of Staff's proposed mechanism clear?

A. Not in our view. For example, the nature of the proposed mechanism discussed on p. 11 is somewhat difficult to reconcile with several additional "reconciliation-type mechanisms" that Staff proposes for other categories of spending (for example storm hardening and response (p. 46) and advanced technology (p. 52)).

Q. What is your recommendation as to these Staff proposals?

A. They should be rejected. Staff has neither provided adequate justification for its asymmetrical true-up mechanism nor adequately explained how it would operate. Moreover, these mechanisms should also be rejected if and to the extent that Staff is attempting to limit the Company's historical flexibility to reprioritize projects and modify project-specific funding within the context of an overall infrastructure program. This 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.

<u>Electric Service Reliability Performance Mechanism ("RPM")</u>

Q. Have you reviewed the testimony of the Staff Infrastructure Panel with respect to the Electric Service Reliability Performance Mechanism ("RPM")?

A. Yes we have.

Q. What does Staff recommend?

A. Staff recommends that the RPM established by the Company's current electric rate plan be continued with the following modifications: (1) changes to the CAIDI and SAIFI targets; (2) 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 target from $4 million to $5 million; (3) increases in the negative rate adjustments for two special projects; (4) a new mechanism using restoration time as a means to measure the Company's performance; and (5) a new mechanism associated with the Company's Remote Monitoring System ("RMS").

Q. Do you agree with the Panel's recommendations?

A. No, we do not. For the reasons explained in our initial testimony, and as discussed in detail by Company witness Zielinski, the Commission should discontinue in its entirety the RPM without instituting any new negative rate adjustment mechanisms. If the Commission nonetheless decides that the RPM should be continued, it should reject the adjustments proposed by the Staff Panel.

Q. What is the basis for your recommendation?

A. 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 subject matter of the performance mechanism, and disproportionate to the aggregate financial exposure of the currently effective RPM.

Q. What approach do you recommend that the Commission take when it determines that the Company should improve its performance for a particular area of its business?

A. 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 plan of action, should the Commission consider whether a performance mechanism and associated negative rate adjustment would be a more effective means for achieving the desired result.

Q. Why do you believe that negative rate adjustments should not be the primary tool used by the Commission to foster changed behavior?

A. As explained in our initial testimony, the negative rate adjustments implemented by the Commission are not what drive the Company to excel. Moreover, assuming for purposes of argument that the threat of financial penalties encourage Company performance relative to a performance metric, the RPM penalties do not accomplish that objective but merely serve to unnecessarily deplete the Company of resources that could otherwise be used to the benefit of customers. While we have seen these dollar assessments being referred to as negative rate adjustments rather than penalties, Staff's recommendations are punitive in nature with no nexus to performance to be achieved.

Q. Why do you say that the RPM penalties do not drive Company performance?

A. As shown by recent incidents on the Company's system, the Company is exposed to substantial financial harm in the form of material 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. Accordingly, assuming a negative financial incentive encourages performance improvement, the Company is already exposed to significant negative financial incentives. The RPM needlessly "piles on" to no effect other than to deplete the Company's resources.

In addition, the components of the RPM should not 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 should be eliminated from the RPM.

Company witness Zielinski addresses the appropriate incentive regulatory framework.

Q. What specific Staff RPM proposal will you address?

A. We will address Staff's proposals concerning service restoration, the remote monitoring system, and the special projects incentive mechanisms. Company witness Lewis will address Staff's proposals concerning electric service reliability performance.

Reliability Performance Mechanism

Q. Please summarize Company witness Lewis's testimony and recommendations.

A. Company witness Lewis recommends reliability threshold standards that differ from the Staff's in five important respects. First, the SAIFI and CAIDI standards must be adjusted to take into consideration the Company's recent implementation of a new Outage Management System 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, reducing Staff'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 will take to address any performance result that does not meet the threshold standards.

Q. What is the Company's proposal, if the Commission determines that reliability performance penalties are appropriate and necessary?

A. Con Edison recommends that a separate phase of this proceeding be established to develop a symmetrical structure of financial incentives and disincentives.

Service Restoration Mechanism

Q. Please address Staff's recommendation to institute a new mechanism using restoration time as a means to measure the Company's performance in restoring service to customers

A. Staff's Restoration Mechanism proposes negative revenue adjustments for failure to meet proposed electric service restoration targets for overhead and underground electric emergency events that interrupt service to customers. For the reasons that we will discuss, the Commission should not institute a new mechanism for this activity. Assuming the Commission nonetheless determines that a new mechanism associated with restoration is necessary, we recommend an alternative to the one proposed by Staff.

Q. Please describe the Company's Electric Comprehensive Emergency Response Program ("CERP").

A. The Company's CERP establishes guidelines for determining the appropriate level of mobilization and response of Company and external resources in a timely manner in response to an incident affecting the electric system. The CERP provides a structured plan to prepare for and address weather related electric emergencies as well as other unexpected system anomalies. Even though the CERP suggests specific actions and responsibilities, the plan is sufficiently flexible to adequately address the unique characteristics associated with system events. This allows each response to be tailored to meet the unique circumstances that each electric emergency presents.

Estimated Time Of Restoration

Q. Does the CERP include ***estimated*** restoration times ("ERTs") for events?

A. Yes. The overhead portion of the CERP states ERTs in the Westchester portion of the plan.

Q. Describe the intent of the ERTs in the CERP.

A. The Con Edison CERP provides ERTs to establish goals that will drive process improvements. The existing targets were established as stretch goals and represent estimated times associated with the damage and number of customer outages from average storms.

Q. Why is it inappropriate to establish a Restoration Reliability Performance Mechanism based upon the number of customers impacted during an event?

A. The adoption of restoration performance targets based upon the number of customers without service does not properly represent the key factor that determines the reasonable estimated restoration time required for an event. While the number of customers is one indicator of the severity of an event, the main factor contributing to the anticipated duration of an outage is the damage sustained during the event. In fact, Con Edison updated its CERP, which was filed this past April with the Commission, to include in its Westchester portion of the plan anticipated damage levels correlating to different level storms. This was included to begin defining the characteristics of storms to help drive process improvements. In the past, Con Edison and many other utilities have defaulted to the use of the number of customers without service to define the scope of an event and required mobilization because this information was usually quickly available through SCADA systems; whereas the full scope of damage sustained is not often immediately available.

Q. Describe how the relationship between customers interrupted and restoration time is not direct.

A. 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. It is the extent of this damage, rather than the number of customers interrupted, that ultimately drives restoration times. For instance, the F2 tornado and the Nor'Easter experienced by Con Edison during 2007 resulted in extensive physical damage to a localized area. As a result of the localized nature of these events the number of customers without service was minimized. In such a situation, the proposed restoration

RPM would require relatively short restoration times reflective of the low number of customers impacted while ignoring the extent of the damage, caused by the severe weather, that needed to be repaired to restore service to those customers.

Overhead System Design

Q. Can you describe the relationship of the design of the overhead electric system to the number of customers interrupted for a given level of storm?

A. Consistent with the strategy to minimize the number of customers affected by storms, past and present reliability programs have been designed to automatically isolate damaged portions of the overhead and almost immediately restore power to customers not on the isolated lines. These designs reduce the number of customers that would otherwise be impacted by a given level of storm damage. The effectiveness of these programs is demonstrated by the low SAIFI indices for outages experienced by Con Edison's customers throughout the year. However, while this design significantly reduces the number of customers affected by a given level of storm damage, it does not reduce the damage that must be repaired before the customers on the isolated lines can be restored. Thus, tying a restoration mechanism to customer outage count does not appropriately account for the amount of work and time required to restore customers to service. Fewer customers without service does not mean less time needed to restore service. Also, the system design and equipment necessary (particularly on the overhead system) to provide reliable service at the levels demonstrated by Con Edison's SAIFI indices increase the probability that the damage realized by the system will require more time than less integrated systems. As previously mentioned, this issue may be mitigated by classifying storms by damage realized instead of the number of customers impacted. 2007 was the first year that Con Edison included in its Bronx/Westchester CERP information regarding the classification of events based upon damage realized. This information was only established as a pilot in the Bronx/Westchester non-network system based upon lessons learned from the severe weather and damage realized during the 2006 events. This information was included to begin correlating the level of damage with the traditional customer outage information and our required emergency response mobilization.

Q. Are there additional factors that impact the restoration effort as a result of the automatic isolation included as part of Con Edison's system design?

A. Yes. Restoration efforts are dependent on established work procedures designed to enhance employee and public safety. As the system operates to minimize the number of customers impacted, additional operating steps are required to restore the system to normal and provide service to customers. This highlights a conflict between the normal operation of the system, which improves the overall distribution system performance, and the resulting complication that ensues during an event where many automated operations by the system ultimately slow the overall restoration performance for those impacted.

Q. What else contributes to the inappropriateness of a penalty mechanism based upon the restoration of customers during significant events?

A. It is generally understood throughout the utility industry that each event has unique characteristics. The proposed Restoration penalty mechanism does not account for the variability and differing characteristics associated with emergencies and the resulting damage. The DPS Staff Infrastructure Panel's testimony on page 64 beginning on line 5, indicates, "[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." The establishment of a Restoration RPM as proposed does not appropriately account for factors wholly outside the Company's control (e.g., extreme weather conditions preventing restoration efforts, access restrictions caused by local conditions and lack of power supply beyond the Company's control) that adversely affect the Company's ability to restore customers. Further, there are a number of independent factors that the Company does not control which influence the Company's ability to plan, prepare for, and respond to the needs of customers before and after an event, including: weather forecasting, tree trimming, mutual aid, ability to compel local governments to properly mitigate identifiable risks, and requests by local government officials to isolate areas and perform activities that do not directly restore service to customers. All of these factors will undermine any attempts to clearly and objectively define "good customer service" on the part of the utility. Some of these will be further discussed below.

Event Classification and Weather Forecasting

Q. Please describe Con Edison's storm classification matrix.

A. The storm classification matrix provides guidance for the level of staffing resources that will be initially deployed in anticipation of an event. The matrix contains six storm classification levels (including the wind and rain characteristics of each storm classification), a range of potential customer outages for each storm classification level, the estimated service restoration time for that number of customer outages due to that class of storm, and the resources that will be initially mobilized and deployed to repair damage and restore customers. The amount of mobilized resources increases as the storm classification level increases. The number of customer outages and the time to complete service restoration are estimates based on past experience with outages from storms. Of course, the Company has had little recent experience with the two hurricane classifications outlined in the CERP matrix.

Q. How is the storm classification matrix used?

A. The storm classification matrix is used to establish the level of staffing resources that will be initially mobilized and deployed for storm response. Initial estimates of resources required for restoration work are based on a preliminary classification of the event before the storm occurs, but 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. Each preliminary storm classification includes a range of customer outages and a target for restoration time for a hypothetical storm of that class based on prior storm-event information. However, because each 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.

Q. What role does weather forecasting play in the initial mobilization and deployment of resources?

A. The weather forecast is the main driver in determining the level of the initial mobilization. This initial mobilization significantly impacts overall restoration times. However, history has shown a wide disparity in forecast versus actual weather.

Tree Trimming

Q. Describe the impact that existing and pending limitations on tree trimming imposed by local laws and public opposition have on the Company's ability to prevent storm related damage to the overhead electric system.

A. The restoration mechanism does not account for the challenges that are being faced as Con Edison focuses on reducing the number of customers who experience outages due to trees. Con Edison's distribution system is subject to tremendous damage as a result of tree contact issues, particularly during storm events. Although Con Edison is attempting to reduce its distribution system exposure, these attempts are being met with some resistance. Recently, the Town of Greenburgh in Westchester County imposed a significant burden upon the Company in its efforts to minimize the number of trees / limbs that impact Con Edison's distribution system. As a result, some avoidable outages will be experienced because Con Edison does not have the legal right to substantially clear areas within the right-of-way where Con Edison only has easement rights. Moreover, although Con Edison may identify a danger tree outside of the right-of-way, (Con Edison has introduced a program change identified in the storm hardening portion of the infrastructure panel testimony for Danger Tree Removal), Con Edison cannot compel the private property owner to remove the tree and alleviate the risk to its distribution system. Thus, despite efforts by Con Edison to reduce the risk to its distribution system through tree trimming, emergency response resources will be burdened, and thus the overall restoration delayed, to address situations that could have been dealt with during non-emergency periods.

Mututal Aid

Q. How does inter-utility mutual aid affect Con Edison's ability to meet the targets set forth by the restoration mechanism?

A. As recognized in Part 105 (Electric Utility Emergency Plans) of the Commission's rules, the utilities rely on the resources of other utilities ("mutual aid") to help repair storm damage and restore service following more serious storm events - Category 3 and above under Con Edison storm classification matrix. Utilities are under no obligation to provide resources.

The proposed restoration mechanism would require Con Edison to rely upon other utilities' willingness to support its restoration efforts and would subject the Company to a $5 million penalty if mutual aid resources were not adequate. During widespread storm events that impact multiple utility service areas, utilities usually address repairs and outages on their own systems before releasing crews to other utilities. The prospect that Staff will seek to impose a restoration penalty mechanism on other utilities will only further induce other utilities to mitigate their risk, and their willingness to provide mutual aid will be delayed until all of their customers are restored. Some may argue that this necessitates procuring mutual aid support proactively from non-New York utilities that are not affected by a particular storm event. However, this argument is flawed because the inherent inaccuracy in weather forecasting results in utilities holding crews, and the time required to procure distant mutual aid from utilities outside the zone of risk can be significant and costly.

Q. How can the Company mitigate the risks associated with mutual aid and meet the needs and expectations of its customers?

A. As customer expectations regarding electric service reliability increase and the frequency and severity of weather related events grow, Con Edison's reliance upon mutual aid may no longer be an adequate solution. The very proposal of a reliability performance mechanism focusing upon restoration suggests that needs and expectations have changed. Accordingly, Con Edison needs to identify the necessary increase in internal resources, including field staffing, required to meet the needs and expectations of customers as reflected in the targets of the reliability performance mechanism. A restoration penalty mechanism should not be implemented before those resources are procured.

Restoration Penalty

Q. How will the implementation of the restoration penalty affect the overall restoration effort?

A. The Restoration penalty is not consistent with Company storm response initiatives that are designed to minimize the impact on the public as a whole. This is something we have made significant strides to improve based upon benchmarking with other utilities and interaction with local governments. For instance, during recent events, we have made decisions that have helped establish "normalcy" to impacted areas, such as allocating significant resources to restore traffic lights, to restore service to schools and to open roadways blocked by trees. While these decisions may not have restored customers in the most expeditious manner, their expedited completion contributed to addressing other needs of the impacted community. The proposed penalty set forth in the RPM forces the Company to focus exclusively on the restoration of customers rather than working collaboratively with local municipalities/boroughs to address local municipal/borough concerns.

Q. What other considerations besides estimated restoration times are significant to a timely response to an event and a better overall measure of reliability and restoration performance?

A. The Company's philosophy toward response to emergencies focuses on reducing the potential impact, minimizing the duration, and communicating openly and effectively. Rather than establishing a RPM focused on only one variable of a response (i.e., customer outages), Con Edison would propose a more comprehensive metric which results in a holistic approach to restoration. Items that might be included are; ICS training of involved emergency responders, notification to critical care customers and Life Sustaining Equipment customers, periodic media releases, daily municipal conference calls where applicable and the establishment and communication of a Global ERT.

Q. How can the proposed Restoration Reliability Performance Mechanism better demonstrate that the restoration efforts made by the Company provide "good customer service?"

A. Con Edison recognizes the impact that its emergency response has upon its customers. Con Edison's emergency preparedness strategy includes the goal of minimizing the duration of outages. Con Edison believes that a holistic approach as set forth above better reflects the Company's emergency response to an event. However, if DPS Staff believes that the best way to capture this is by prescribing a defined time period, then the restoration timeframes need to be determined after appropriate analysis, benchmarking, and inclusion of pertinent factors.

Q. What would the Company propose in terms of exploring different alternatives to Staff's Restoration Reliability Performance Mechanism?

A. As demonstrated by the discussion above, determining what constitutes "good service" from a customer restoration standpoint is a complicated task which requires many different, and often competing, factors to be weighed. Staff's Restoration RPM proposal does not take many of these factors into account, which may ironically result in worse rather than better overall service for customers and communities. Given the analysis and careful consideration required to properly address this issue, the Company would recommend addressing this matter in a separate phase of this proceeding. The Company, Staff and any interested parties would work collaboratively to develop relevant metrics, as well as appropriate levels of balanced incentives.

Q. How does DPS testimony throughout the electric rate case conflict with the establishment of a restoration mechanism?

A. Although DPS Staff proposes a significant penalty for failing to make restoration times for given events, they deny (subject to future consideration based upon the recommendations contained in the recent PSC audit) or reduce many program changes that directly impact the Company's ability to restore customers expeditiously. Staff proposes to eliminate the Coastal Storm Mitigation Plan which seeks to eliminate the risks associated with storm surge. Staff 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 minimizing the duration of outages and communicating openly and effectively during outage events. Additionally, the Control Center Screening Group, an organization that would help prioritize restoration work and enhance restoration times was eliminated. Further, many of the Storm Hardening program changes that were proposed were reduced. The Storm Hardening programs are designed to minimize the number of customers impacted by system events. These denials or reductions seem inconsistent with the establishment of a restoration penalty mechanism. Finally, the concept that a single metric can capture the success of a restoration effort is inconsistent with the recent audit recommendation that Con Edison needs to take a more holistic approach to its restoration efforts and stop focusing on "getting the lights on."

Remote Monitoring System Mechanism

Q. Please address Staff's recommendation to institute a new mechanism associated with the Remote Monitoring System ("RMS").

A. For the reasons we will explain, the Commission should not institute a new mechanism for this activity. If the Commission does adopt Staff's mechanism the Company's rate year revenue requirement should be increased for the costs that the Company would incur to meet the performance target and the severe penalties recommended by Staff should be brought in line with the penalty levels for the other "special projects" that Staff is proposing.

Q. Staff's Infrastructure Panel proposes to establish a new incentive mechanism for RMS availability. What is Con Edison's position on this proposal?

A. Staff's proposed incentive mechanism is entirely unnecessary. Con Edison has been working since 2004 to develop upgraded RMS equipment and technology. For the last year, Con Edison has had a program in place that has changed out and upgraded RMS equipment and improved RMS maintenance processes. This program has substantially improved RMS availability to a current level of 95% availability in each of the Company's operating regions.

Q. What are the benefits of the RMS?

A. The Remote Monitoring System provides near real-time transformer data that assists our Distribution Engineering, Regional Engineering, Field Engineering, and Emergency Response Groups in a variety of functions such as monitoring transformer loading and its network protector switch status (open or close), providing data used in developing engineering plans for new customers, reinforcement of the network system, and most recently measuring temperature and pressure within the transformer.

Q. Please describe the current RMS.

A. 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 from the transmitter to the RMS receiver installed in the network's supply substation utilizing the transformer's high-voltage distribution feeder as a communications medium. This method of communications is known as a Power Line Carrier or PLC method. 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.

The Company has a total of 23,615 transmitters on its system. Forty two percent of these are 1st generation transmitters, which were installed beginning in 1982 when the RMS program was first implemented and are about 20 years average age.

The 2nd generation units currently in service comprise 38% 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, manufactured by ETI Corporation, 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.

Since the system has evolved over a period of two decades and continues to operate, it remains a mixture of various technologies and components. In its current rate request, the Company has proposed to bring the system up to currently available technology (3rd 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.

Q. Please provide an overview of Con Edison's efforts to improve its ability to monitor network transformers

A. In the late 1970's, Con Edison conceptualized a system to remotely monitor the switch position of the network protectors on its distribution network transformers. This Remote Monitoring System was subsequently developed by Hazeltine Corporation. Following trials of prototype units, a full three-phase system was installed over a 10-year period beginning in 1982. Con Edison's RMS was the first such system installed, and remains the largest system of its type in the country.

The system quickly became one of the main lines of data acquisition for network protectors and transformers, and remains so to this day. The original system monitored transformer load, switch open or close status, and transformer high oil temperature.

Beginning in 1996, second generation units, which had increased monitoring ability, were deployed for new transformer installations and replacements. Although this development added monitoring points to the system, very little improvement was achieved in the reliability of system components and communication. During this period of development, Hazeltine Corporation owned the patents for the system and remained the only manufacturer of the RMS system equipment. Competitive products reflecting new technologies were unavailable. While the Company worked with Hazeltine to continue developing and enhancing the RMS transmitter unit, efforts to encourage Hazeltine to enhance the substation receiver were unsuccessful.

After Hazeltine Corporation was sold to BAE Systems Inc. in 1999, the new owner sought to phase out production of the RMS system. Con Edison was the only customer at the time, and without additional cost increases above the high prices already being charged for the components, BAE would not continue with the production or development of RMS equipment.

With the future of RMS in jeopardy, Con Edison undertook a project in 2000 to develop the next generation for system monitoring, called the Secondary Underground Network Distribution Automation System ("SUNDAS"), that would replace RMS for monitoring network transformers. The Company achieved initial success and actually installed a working SUNDAS in the Hunter network. The SUNDAS technology entailed use of a high frequency PLC signal injected on the secondary network grid and used as a local area network ("LAN") two-way communications medium to communicate data from the network protector relays and the secondary sensors. However, the carriers providing the communications network, initially AT&T and then Verizon, discontinued providing the cellular digital packet data service necessary to operate the system. This rendered obsolete the modem hardware in the communications concentrators and made the data collection software inoperable. After investigating alternative communications systems, the Company concluded that a similar communications setback could occur again after the system was deployed and force resort to another costly alternative. The additional costs and effort related to the hardware and software redesign plus the anticipated very high deployment costs of the system, prompted the

Company to abandon this project in 2004 and to focus on the enhancement of its existing RMS.

Beginning in 2004, Con Edison took advantage of then expiring original patents to promote RMS technology advances so it could replace outdated equipment that was failing at greater rates than forecast by Hazeltine. Thus, the Company partnered with Digitalgrid Inc. ("DGI") and Electronic Technology Inc. ("ETI") to maintain support for the existing equipment and continue to develop the RMS system enhancements. In 2004 and 2005, Con Edison, DGI and ETI developed, lab-tested and field-tested a new RMS receiver that provides increased sensitivity to data signals transmitted from the RMS transmitters and capable of receiving a broader range of frequency variations. It is equipped with remote self-diagnosis tools, including pick-up coil testing and improved data error correction, to alert us when critical components of the RMS system have failed. The receivers are also designed to process more information from the field, affording us the opportunity to include additional status inputs from the RMS transmitters. The Company installed eleven new receivers in 2005 and eleven in 2006. Since the new receivers provided superior performance, the Company accelerated their installation in all their area substations. By summer of 2007, all 62 substation receivers were replaced at a total cost of $5.1 million, resulting in a significantly improved reporting rate of RMS transmitters.

Also in 2004 the Company worked with manufacturers to produce a new third generation RMS transmitter that offers a higher output capability, and is outfitted to provide additional analog and digital sensory inputs for transformer temperature and pressure, along with 3 phases of voltage. This new transmitter is now used for all new and replacement installations. It is installed inside the network protector housing and is better protected from the external environment. We also developed a new plug-and-play boot assembly that made it possible to install 2nd and 3rd generation transmitters externally, permitting field crews to make repairs more efficiently on externally installed transmitters. In addition, we launched an RMS pick-up coil testing and replacement initiative in early 2006. Much of this testing required manual field checks of pick-up coils at the feeder cubicle in the substations. The new receivers have built-in hardware/software that allows us to check the pick-up coils remotely.

The Company, DGI and ETI continue to develop and deploy advanced RMS technology. These developments include attempts to improve reporting capabilities, lower failure rates, improve operating characteristics and add functionalities. Some of the recent enhancements are: remote monitoring of oil temperature, tank pressure, and oil level, improvements in reporting rates, improved pick-up coil testing, and stray voltage monitoring.

Q. Describe Con Edison's current program to improve RMS reporting.

A. Con Edison's October 2006 internal report on the Long Island City network outages recommended that the Company improve RMS reporting. In September 2006, the RMS availability by region was: 92 percent in the Bronx Westchester Region, 89 percent in the Manhattan Region, and 83 percent in the Brooklyn Queens Region. The Company assembled both a core team and teams in each region to build on the work performed since 2004 (transmitter, receiver, and pick-up coil replacement) in order to improve RMS reporting as much as possible. This effort first achieved a 95 percent RMS availability within each region in April 2007.

Q. What is the basis for 95 percent RMS availability?

A. Hazeltine Corporation, the original manufacturer, claimed the mean time between failures ("MTBF") was 60 years for the 1st generation transmitter and 62.5 years for the 2nd generation units and that an overall 95 percent system availability could be expected at optimal performance. However, actual experience has demonstrated that this was significantly overstated, and in reality the actual MTBF for the 1st and 2nd generation transmitters is less than 17 years.

Another important reason for less than optimal RMS reporting is the 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.

Over a period of two decades, Con Edison maintained a long-term RMS maintenance contract with Hazeltine to provide system maintenance, testing, and calibration of the PLC signals. They were not able to determine why some feeders reported less than others and ultimately concluded that geography and disturbances in the environment were the reasons.

Q. What is the current RMS reporting rate?

A. Con Edison has 60 networks. For the month of August 2007, RMS availability exceeded 95 percent in 42 networks and was less than 95 percent in 18 networks. The RMS availability by region was: 96.6 percent in the Bronx Westchester Region (4 networks above 95 percent; 3 networks below 95 percent); 96.4 percent in the Manhattan Region (27 networks above 95 percent; 8 networks below 95 percent); and 94.5 percent in the Brooklyn Queens Region (11 networks above 95 percent; 7 networks below 95 percent).

Q. Has Con Edison achieved 95 percent reporting availability in all networks simultaneously since 2000?

A. No. Con Edison has never achieved 95 percent RMS availability in all networks simultaneously. As we stated previously, in April 2007, each region first achieved an availability of 95 percent reflecting availability above 95 percent in some networks and below 95 percent in other networks.

Q. Does Con Edison plan to achieve 95 percent RMS availability in each network?

A. The Company goal is to achieve 95% reporting rate, however it is at this juncture an aggressive goal and even then we would not expect to achieve 95 percent in all areas. We are upgrading technology and processes to improve performance. The Company's goal is to achieve 95 percent RMS availability on a regional basis reflecting the average availability of each network in the region with no network at less than 90 percent availability. Currently we meet that goal in the Manhattan and Bronx-Westchester Regions. The Brooklyn-Queens Region has an average 94.5 percent availability with two networks at 89.5 and 87.8 percent availability.

Q. What is Con Edison's long-term goal for RMS availability?

A. Con Edison will strive to maintain 95 percent RMS availability on a regional basis reflecting the average availability of each network in the region with no network at less than 90 percent availability.

Q. Can the Company maintain 95 percent RMS availability over the long-term?

A. Maintaining 95 percent RMS availability across each region at all times is uncertain. The Company will continue its program to upgrade the system with the 3rd generation transmitter, investigate networks with less than 95 percent reporting to determine the cause, and continue to develop solutions for improvement in technology. As discussed previously, the Company has already invested substantially when it replaced all receivers in the substations.

Nonetheless, the Company is uncertain whether 95 percent can be maintained every month on a regional basis, much less across the board every month for the 60 networks as Staff proposes. One important consideration is that about 21,500 first and second generation RMS transmitters remain in the field, some since the 1980s. 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 the third generation units that are installed inside the protected environment of the network protector housing and are less prone to water damage. Con Edison has reflected the costs of this ten-year upgrade program in the rate year revenue requirement in this proceeding.

Q. Are there system requirements that could affect RMS availability?

A. Yes. Repairs and upgrades are dependent on the availability of construction forces. In any given month, 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 availability. A feeder outage is required to replace a defective coil entailing manpower from both Electric Operations 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.

Q. How does the Company measure RMS availability?

A. The overall reporting rate allows the Company to ascertain how many locations in the network report data to the total number of locations that have the RMS equipment installed. RMS availability is established on a monthly basis. The RMS reporting rate is based on the following formula: (Adjusted Total DAMS Vaults - UNR's)/Adjusted Total DAMS Vaults X 100 = Monthly Reporting Rate percentage.

- The Adjusted Total DAMS Vaults removes from the formula vault locations that are in Banks Off status or part of a feeder contingency for the month.
- The UNR's are vault locations that are "Unable to Report" once during the month.

The Company has used this method for measuring RMS availability since the system was installed.

Q. Is an incentive mechanism needed to encourage the Company to maintain RMS availability?

A. An incentive mechanism is not needed to encourage Con Edison to maintain RMS availability. The Company has set an ambitious goal for RMS availability by achieving 95 percent RMS availability on a regional basis with no network at less than 90 percent availability. The Company's successful efforts since 2004 to modernize the legacy RMS system and its progress in achieving 95 percent RMS availability demonstrates the Company's commitment to achieve and maintain a 95 percent RMS availability.

Q. Is Staff's incentive proposal reasonable?

A. As we have just stated, an incentive mechanism is not needed. Staff's proposed incentive target - 95 percent RMS availability every month in every one of the Company's 60 networks - is unreasonably aggressive. We have previously discussed uncertainties that make unrealistic an expectation of 95 percent availability in all 60 networks each month. These include system conditions that affect construction force availability to make repairs and upgrades of transmitters that have a six percent annual failure rate, and that dictate the timing of feeder outages that are required to replace RMS pick-up coils that have a three percent annual failure rate. The Company has set an ambitious goal to for RMS availability by achieving 95 percent RMS availability on a regional basis with no network at less than 90 percent availability. We are not certain that the Company can achieve this goal every month. Nevertheless, the Company has made and continues to make significant progress in RMS availability, and the Company has set an aggressive target to improve performance.

Q. Please comment on Staff's proposed $10 million penalty per network for failure to achieve 95 percent RMS availability in any month with no limitation on liability.

A. The penalty amount is obviously radically disproportionate to $3 million penalty amounts proposed for the other "special projects" in Staff's Reliability Performance Mechanism proposal that Staff believes are adequate to motivate Company conduct. Staff has made no showing why such significant potential penalties, with the potential for monthly application and unlimited liability, are warranted for this incentive mechanism. 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 ratepayers. If Staff's proposed penalty mechanism for RMS availability were to be adopted by the Commission, the penalty level should be a maximum of $3 million per year. In addition, should the 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.

Q. Please comment on the additional costs for increased staffing, specialized resources and equipment that would be required to maintain 95 percent availability in each network every month.

A. 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 (i.e. RMS component replacements required to ensure a 95 percent reporting rate in each network every month) in total annual equipment costs 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 include 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 every month is estimated at incremental increase of $15 million annually to the existing program.

Special Projects

Q. Please address Staff's proposal to maintain the "special projects" performance mechanisms and to increase the negative rate adjustment for two special projects - "No-Current Street Lights and Traffic Signals" and "Over-Duty Circuit Breaker Replacements."

A. Con Edison has met the targets for all of the special project categories and has incurred no penalties for any special projects since these were established in 2005.

City witness Galgano points out that Con Edison has complied with the requirement in the current rate plan to "energize at least 85% of new streetlights within a 90-day period and all new streetlights within 6 months." Significantly, this is the one "special project" in the rate plan that is not enforced with a penalty. Con Edison's compliance with this performance target demonstrates that a penalty mechanism is not required to achieve the performance level that Staff seeks.

Consistent with our initial testimony, we propose that for all special project categories the performance standards be continued without penalty measures and that the Company continue to report its performance annually.

Q. Please address Staff's proposal to increase the negative rate adjustment for the special projects "No-Current Street Lights and Traffic Signals" and "Over-Duty Circuit Breaker Replacements."

A. Staff proposes to increase the negative adjustment for the special project "No-Current Street Lights and Traffic v Signals" from $1 million to $1.5 million for the winter month period and likewise for the summer month period. This proposal should be rejected as arbitrary, establishing no nexus between the amount of the increased negative rate adjustment and the targeted performance goals. Specifically, 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. Staff certainly disregards this uniformity "logic" in proposing $10 million per violation penalties, with unlimited liability, for its proposed addition of Remote Monitoring System metrics to the "special project" categories.

Nor is there any 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.

Q. Please address Staff's proposal to increase the negative rate adjustment for the special project "Over-Duty Circuit Breaker Replacements."

A. The circuit breaker incentive mechanism is one of the four "special projects" mechanisms from the Company current rate plan that Staff proposes to continue. However, Staff's testimony does not mention that Staff is proposing a substantial increase in the penalty for this mechanism. The increase is shown only in Staff's Exhibit ___ (SIP-3) page 19 of 22. There Staff includes 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 current RPM also provides for the replacement of 60 breakers per year, the revenue adjustment is $100,000 per breaker not replaced measured against a two-year target of 120 total breakers over the two year period ended March 31, 2008. Now Staff seeks a penalty of $3 million for failure to replace one circuit breaker less than 60 in the rate year.

Q. Is continuation of the incentive mechanism for over-duty circuit breaker replacement warranted?

A. No. As stated in our initial testimony, the Company's revenue requirement 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 over-duty circuit breakers, and the Company expects to replace at least 60 in the current rate year system conditions permitting. 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.

Q. What is Staff's rationale for proposing this change?

A. Staff has provided no justification whatsoever for increasing the level of this penalty from $100,000 per breaker to a lump sum $3 million dollars for failing to replace even one breaker below 60. Staff does not even mention this proposed change in its testimony. Moreover, the proposed increase in penalty is irrational, and it is counterproductive from a reliability perspective. In response to the Company's exceeding Staff's performance targets, Staff proposes to dramatically increase the penalty. This unduly harsh penalty would encourage the Company to take feeders out of service in order to replace breakers and avoid the penalty when system conditions might warrant otherwise for network reliability.

Furthermore, this penalty mechanism is counterproductive to the reason for the mechanism stated in Exhibit ___ (SIP-3), page 19 of 22 - "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 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 does not encourage the Company to finish a substation. It encourages the Company to focus on bulk breaker replacements at whatever substation a bus section outage can be obtained.

Q. What does the Company recommend with respect to Staff's proposal?

A. The Commission should reject Staff's proposal for continuing this penalty mechanism. However, if the Commission were to conclude that that there is reason to continue this mechanism, then the $100,000 per breaker penalty should continue. Staff considered this penalty appropriate in the current agreement and does not say why it should be increased.

Other Performance Mechanism Proposals

Q. Have you reviewed the proposals of the Staff Consumer Services Panel and CPB's Mr. Elfner to increase the financial penalties associated with the Outage Notification Incentive Mechanism ("ONIM")?

A. Yes, we have.

Q. Please summarize their proposals.

A. Staff recommends that the Company's financial exposure be doubled from $150,000 to $300,000 for each activity either not completed within the prescribed time period or which does not contain the required information; that an additional activity be added to the list of notification activities - holding conference calls to brief public officials; that the total amount at risk under the ONIM be increased from $4 million to $8 million; and that the total amount at risk under the CSPI be increased from $36 million to $40 million.

Mr. 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.

Q. What reasons do they provide for their recommendations?

A. Staff says the LIC and Westchester reports both determined that the ONIM be reexamined in the Company's next rate case, that performance payment levels be adjusted upward, and that there should be discussions about including an additional activity - holding conference calls to brief public officials about the status of restoration and other outage-related information. CPB also cites the Company's performance during outages as a basis for its recommendations.

Q. Do you agree with these recommendations?

A. No, we do not. First, these proposals should be rejected for many of the same reasons we discussed above regarding the Staff proposals to modify and add to the RPM. In addition, the increased penalty amounts proposed by Staff and CPB are arbitrary. Moreover, in its responses to the LIC and Westchester recommendations, the Company did not dispute that the ONIM be re-examined in the Company's next electric rate case. The Company has demonstrated that it can and will implement changes to its outage notification performance without the need for negative financial incentives, and certainly not above and beyond the existing ONIM penalties. In fact the Company has already implemented conference calls to brief public officials without criticism from Staff. There is no need to establish negative financial incentives for a process that is working well.

Q. Have you reviewed Mr. Koda's proposal on behalf of Local 1-2 to institute a manhole congestion incentive mechanism?

A. Yes, we have.

Q. What is your recommendation?

A. We recommend that the Commission reject Mr. Koda's proposal.

Q. Please comment on Mr. Koda's allegation that the Company has a questionable history of manhole incidents over the past decade.

A. Of the 270,000 underground structures, over the last eight years less than 1 percent of the structures experienced a manhole incident. Consistently over the years, we have found a strong correlation between the amount of salt distributed by the City and the number of underground structure events. In 2006 there was a 25 percent reduction in underground structure incidents.

Q. Mr. Koda alleges that unacceptable levels of manhole congestion hindered the restoration of service during last summer's LIC outage, and that such congestion was conducive to arcing and resulting fires. Does Mr. Koda explain what he means by manhole congestion?

A. No, he does not.

Q. Please respond to his allegations regarding the unacceptable level of manhole congestion.

A. Over the last two years, 120,000 underground structures have been inspected as part of our secondary reconstructing project. Out of these inspections, less than half a percent of the structures required enlargement.

Q. Has Mr. Koda proposed a specific mechanism or rate adjustment to address his concerns?

A. No, he did not.

Q. Please summarize your conclusions regarding Mr. Koda's testimony on this matter.

A. Mr. Koda's allegations as to the Company's performance as to manhole incidents and manhole congestion are unfounded for the reasons we explain above, and since he has made no proposal to address these alleged concerns that may be reasonably evaluated, the Commission should reject Mr. Koda's recommendation.

Q. Please comment on Staff's proposal, as indicated in Exhibit SIP-3, that the new performance measures (restoration and

RMS incentives) and the increased penalties (CAIDI measures and "no-current streetlights") become effective January 1, 2008.

A. Under Con Edison current rate plan the current RPM performance measures and penalties remain in effect "through the end of the rate plan and thereafter until electric base delivery rates are reset by the Commission." Moreover, the Company should not be subject to a new penalty being applied to its performance during a past period. The new measures and increased penalties proposed in Exhibit SIP-3 should not become effective before the current electric rate plan expires.

Q. Does this conclude your update and rebuttal testimony?

A. Yes.

Capital Spending (Historical & Required)

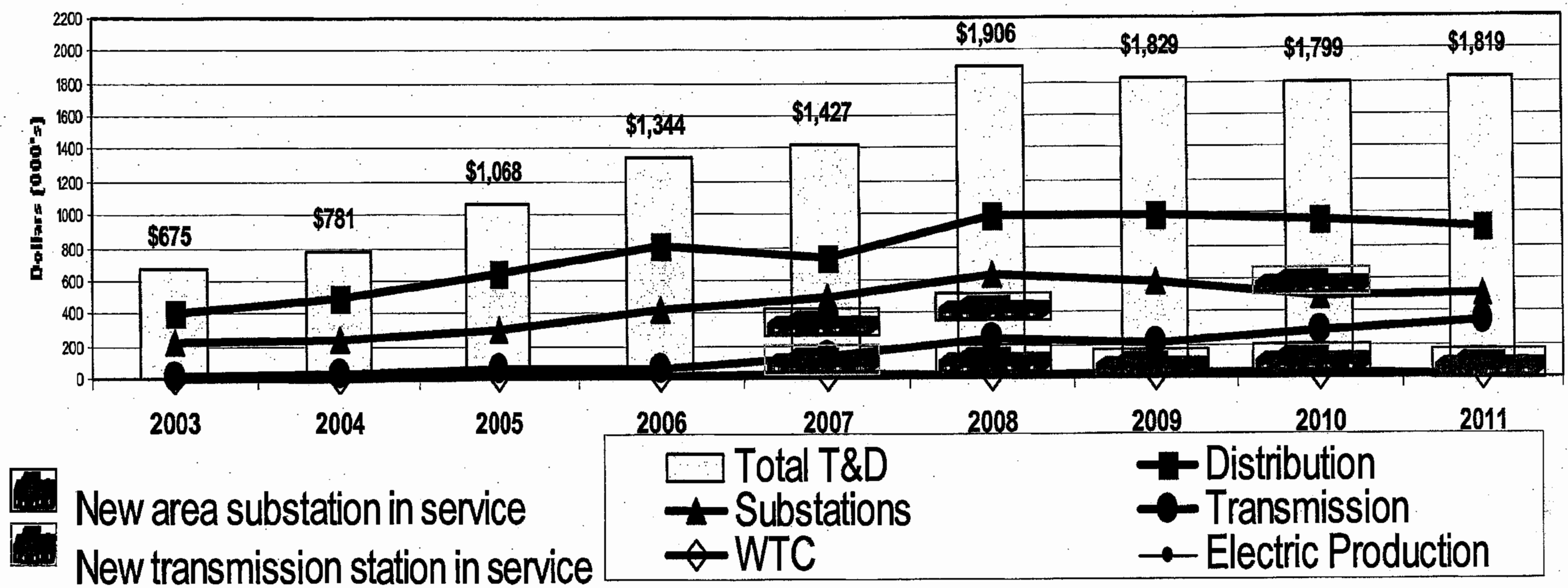


Exhibit__ (IIP-1)
Revised
Page 1 of 1

conEdison

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
SUBSTATION OPERATIONS CAPITAL PROJECTS

	$000s		
	Rate Case Submission		
DESCRIPTION	2008 Update	2009 Update	2010 Update
SUPPORT ECONOMIC GROWTH	$ 453,264	$ 409,500	$ 321,500
Astor - Establish New Area Station	33,000	6,000	-
Cedar St. - Third Transformer and 138kV Feeder	2,400	-	-
Elmsford - Install New Substation	20,000	28,500	17,000
Emergent Load Relief Program	3,000	3,000	3,000
Fox Hills - Install Two New Feeder Positions	1,600	-	-
Fresh Kills - Install 30 MVAR Capacitor Bank	2,000	2,000	-
Transformer Cooling	1,000	1,000	500
Gowanus - Establish New Transmission Station	-	-	5,000
Hillside - Establish New Area Substation	300	2,700	-
Hudson Yards - Establish New Area Station	-	44,000	22,000
Idlewild - Establish New Area Station	700	6,300	-
Land Acquisition for Future New Substations	5,000	45,000	55,000
Mott Haven - Establish 345 kV Switching Station and Area Station	8,000	-	-
Nevins St. - Establish New Area Station	3,000	-	-
Newtown - Establish New Area Station	59,000	72,000	45,000
Parkview- Establish New Area Station	64,864	-	-
Queens - Establish New Transmission Station	-	-	4,000
Rockview - Establish New Area Substation	15,400	-	-
West Side - Establish New Transmission Switching Station	135,000	50,000	75,000
Woodrow - Install 3rd Transformer with 138kV Feeder	15,000	22,000	6,000
York - Establish New Area Substation	79,000	97,000	34,000
GENERATION INTERCONNECTION			
Expansion of 49th Street Substation	-	10,000	20,000
Install Phase Angle Regulator	4,000	10,000	20,000
Install Series Reactor	1,000	10,000	15,000
Sub-Total	$ 453,264	$ 409,500	$ 321,500
IMPROVE RELIABILITY	$ 140,995	$ 142,115	$ 144,585
EQUIPMENT			
Condition Based Monitoring/Sage Monitoring	250	250	250
Obsolete 138kV Circuit Breaker Program	7,700	7,700	7,700
Obsolete Circuit Switcher Replacement	500	500	500
Replace 345kV Circuit Breaker Other Than ATB and Compressors	7,000	7,000	7,000
Replace Disconnect Switches	2,900	3,600	3,600
Replace Obsolete Transformers	17,200	13,000	21,000
Replace Overdutied 13/27kV Circuit Breaker Programs	8,800	8,800	8,800
Spare Equipment Other than Transformer	1,500	1,500	1,500
Spare Transformer Program	21,200	33,960	22,285
Sub-Total	$ 67,050	$ 76,310	$ 72,635
RELAY			
Control Cable Upgrade Program	1,000	1,000	1,000
Modify Auto Underfrequency Loadshedding	1,385	-	-
Reduce Fault Clearing Time	5,200	-	-
Relay Modifications	2,500	2,500	2,500
Upgrade Analog Circuits To Digital Fiber	2,000	2,000	2,000
Sub-Total	$ 12,085	$ 5,500	$ 5,500

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
SUBSTATION OPERATIONS CAPITAL PROJECTS

	$000s		
	Rate Case Submission		
DESCRIPTION	2008 Update	2009 Update	2010 Update
MISCELLANEOUS COMPONENTS			
Additional G&T Devices	1,000	1,000	1,000
Area Substation Reliability	8,500	8,500	8,500
Battery & Rectifier Replacement	3,500	3,500	3,500
Capacitor Cable Upgrade Program	3,000	3,000	3,000
Category Alarms	2,250	2,250	2,250
Construct Relay Enclosure Houses	1,500	1,500	1,500
Corona Settlement	1,000	1,000	1,000
Diesels / Blackstart Restoration (Phase 2) - Upgrade Station L & P	600	1,200	1,000
East River Complex - Install Wall	-	2,500	2,500
Facility Upgrade	6,000	6,000	6,000
Fire Protection Program	500	500	500
High Voltage Test Sets	6,500	2,000	2,000
Install 138kV Breakers 7 & 8 and Third Cap Bank - Jamaica	3,000	-	-
New Maximo Upgrade	400	400	-
Rapid Restore Enhancements- Mapping/Modeling System	200	200	200
Reinforced Ground Grid	500	500	500
Revenue Metering Upgrade	500	500	500
Roof Replacement	3,000	3,000	3,000
Small Capital	6,000	6,000	6,000
SOCCS - RTU Replacement	3,000	3,000	3,000
Substation Automation	2,000	2,000	2,000
Substation Automation - East River	3,000	3,000	3,000
Substation Continuance - Buchanan	-	-	5,000
Substation Continuance - E179th Street	-	-	2,500
Substation Continuance - E63rd Street	2,500	5,000	5,000
Substation Continuance - White Plains	-	550	-
Substation Loss Contingency	2,000	2,000	2,000
Switchgear Enclosure Upgrade Program	500	500	500
Technology Improvements- Work Permit System, T1 Lines, Phase #1 Substation Central	310	705	500
Upgrade 13kV L&P Transformer - Fresh Kills	600	-	-
Sub-Total	$ 61,860	$ 60,305	$ 66,450
ENVIRONMENTAL	$ 13,500	$ 13,000	$ 15,000
SPCC Plan for Transmission Cable System	500	-	-
Environmental Risk	3,500	3,500	3,500
Pumping Plant Improvement	8,500	8,500	8,500
PURS Supervisory Control & Data Acquisition	1,000	1,000	3,000
Sub-Total	$ 13,500	$ 13,000	$ 15,000
SECURITY	$ 4,100	$ 4,100	$ 4,000
Security Enhancements	4,100	4,100	4,000
Sub-Total	$ 4,100	$ 4,100	$ 4,000
TOTAL SUBSTATION OPERATIONS	611,859	568,715	485,085

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
SUBSTATION OPERATIONS O&M PROGRAMS

		($000)			
		Rate Case Submission			
Program Description	Category	Actual 2006	Forecast RYE 2009	Forecast RYE 2010	Forecast RYE 2011
Telecommunications (Digital Fiber Optics/ System Expansion)	Advanced Technology		480	480	480
Advanced Control Systems Group	Advanced Technology		792	842	892
SF6 Gas Emissions Reduction Program	Environmental		200	200	200
Cable Cooling System Maintenance	Improve Reliability	580	880	880	880
Dynamic Feeder Rating System	Improve Reliability		165	205	245
Field Operation Trainers	Improve Reliability		153	153	153
Operator Staffing Augmentation for Existing Facilities	Improve Reliability	34,665	36,313	36,313	36,313
Relay Set Point Adjustment for Magnetic Inrush	Improve Reliability		234	234	-
Structural Integrity / Station Betterment	Improve Reliability		2,000	2,000	2,000
Flame Retardant Clothing	Safety		355	355	355
SSO Staffing - New Facilities	Support Economic Growth		4,701	4,968	5,502
Totals		$35,245	$46,273	$46,630	$47,020

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
SYSTEM AND TRANSMISSION OPERATIONS CAPITAL PROJECTS
TRANSMISSION OPERATIONS CAPITAL PROJECTS / PROGRAMS

	$000s		
	Rate Case Submission		
DESCRIPTION	2008 Update	2009 Update	2010 Update
ENVIRONMENTAL	$ 1,750	$ 1,750	$ 1,750
DEC Program Line	1,750	1,750	
Environmental Enhancements			1,750
Sub-Total	$ 1,750	$ 1,750	$ 1,750
IMPROVE RELIABILITY	$ 185,100	$ 139,300	$ 134,300
M-Line Tower Relocation	1,500	1,500	-
Feeder M56 (Westside Switching)	-	10,000	20,000
Transmission Feeder Failures	5,000	5,000	5,000
Reinforcement - Feeder M29	143,000	73,000	36,000
Feeder M51	6,700	6,700	6,700
Cable System Enhancement - Pothead Alarms	500	500	500
Millwood - Replace Wood Poles W/Steel Poles	4,000	-	-
Replace 69kv Feeders On QBB	-	-	11,300
Emergent Transmission Reliability	5,000	10,000	10,000
Feeder 38M72 Upgrade	4,200	6,300	10,500
Replace Feeder 69M43/69M44 With 38M53 & 38M54	3,700	-	-
Reinforce Hudson River Crossing Towers - Feeders Y88 and Y94	2,400	5,100	-
Replace 138kv Feeders 18001 & 18002	5,000	15,000	20,000
Replace Feeder 69M41 & 69M45	-	-	8,000
Re-Conductor Dunwoodie – Sprain Brook Transmission Corridor - Feeders 99941 And 99942	2,000	4,000	4,000
Upgrade Overhead 345kv Transmission Structures	2,100	2,200	2,300
Sub-Total	$ 185,100	$ 139,300	$134,300
SUPPORT ECONOMIC GROWTH	$ 37,400	$ 55,600	$ 137,000
Re-Conductor Feeders 69M61 -- 69M65	-	-	5,000
East 13th Street Load Pocket	36,400	54,600	91,000
Mott Haven / East Queens / Gowanus - 2- 345kv Feeders	-	-	40,000
Dynamic Feeder Rating	1,000	1,000	1,000
Sub-Total	$ 37,400	$ 55,600	$137,000
* TOTAL TRANSMISSION OPERATIONS	224,250	196,650	273,050

* Note - Interrogatory pending with Staff as to projects/progams reduction.

	($000)		
	Rate Case Submission		
DESCRIPTION	2008	2009	2010
Support Economic Growth	$ 339,514	$ 336,534	$ 312,193
New Business			
- ED1 costs	$ 125,000	$ 125,000	$ 125,000
- Meter Installation	$ 19,320	$ 17,721	$ 17,771
Sub-Total	$ 144,320	$ 142,721	$ 142,771
System Reinforcement Area SS Load Relief			
Bruckner 2008 8MX NY Post	$ 200	$ -	$ -
179th Mott Haven 25 MW	$ 5,000	$ 5,000	$ -
Cedar Street 3rd Bank	$ 500	$ -	$ -
Elmsford Refurbishment 2008	$ 1,300	$ 2,000	$ -
White Plains to Rockview S/S	$ -	$ -	$ -
Granite Hill to Rockview	$ 4,000	$ -	$ -
Newtown	$ 10,000	$ 10,000	$ 8,000
Astor (Herald Sq. Transfer)	$ 5,000	$ 3,000	$ -
Penn/Waterside	$ 2,400	$ -	$ -
Parkview (East Harlem Network)	$ 10,000	$ -	$ -
York Substation (Hunter Transfer 88MW)	$ 2,000	$ 8,000	$ 5,000
Fresh Kills Load Transfer Capability	$ -	$ 3,000	$ 6,000
Willowbrook	$ -	$ 1,200	$ -
Wainwright	$ -	$ -	$ 1,200
Rockefeller Center to Astor	$ 5,000	$ 8,000	$ -
Randall's Island	$ 3,000	$ 2,500	$ -
Roosevelt (30MW)	$ -	$ -	$ 500
Madison (30MW)	$ -	$ -	$ 4,000
Lenox Hill to York Substation	$ -	$ 5,500	$ 1,500
Sub-Total	$ 48,400	$ 48,200	$ 26,200
Base Growth / Relief			
Primary Feeder Relief	$ 40,497	$ 41,003	$ 41,523
NonNetwork Fdr Relief (Open Wire)	$ 3,000	$ 1,800	$ 1,800
4 kV Feeder & Wire Relief	$ 10,605	$ 9,736	$ 9,872
Overhead Transformer Relief	$ 3,150	$ 3,150	$ 3,150
Secondary Main Relief	$ 2,150	$ 2,150	$ 1,650
Sub-Total	$ 59,402	$ 57,839	$ 57,995
Distribution Substation			
Distribution Substation Load Relief	$ 6,400	$ 6,400	$ 6,400
Sub-Total	$ 6,400	$ 6,400	$ 6,400
Meter Purchase	$ 11,967	$ 12,349	$ 9,802
Transformer Purchase	$ 69,025	$ 69,025	$ 69,025
Improve Reliability	$ 533,895	$ 528,084	$ 532,669
Emergency Primary Cable Replacement	$ 35,536	$ 35,206	$ 34,206
Overhead	$ 8,267	$ 8,267	$ 8,267
- Secondary Open Mains (incl. conduit)	$ 92,327	$ 85,363	$ 81,359
- Temporary Services (incl. conduit)	$ 16,053	$ 16,053	$ 16,053
- Street Lights (incl. conduit)	$ 15,253	$ 15,253	$ 15,003
- Transformer Installation	$ 23,279	$ 21,594	$ 21,594
(Primary) Cable Crossings	$ 8,833	$ 9,033	$ 14,329
HiPot	$ 6,303	$ 6,399	$ 6,498
PILC	$ 39,200	$ 39,200	$ 39,200
Transformer Remote Monitoring System	$ 20,645	$ 18,617	$ 17,929
Network/Non Network Transformers >125%	$ 15,525	$ 14,901	$ 15,288
Network transformer replacements >115% <125%	$ 25,913	$ 25,120	$ 19,402
Network Transformer Replacements >100% <115%	$ 51,466	$ 51,463	$ 58,184
Sectionalizing Switches (SF6)	$ 3,468	$ 4,243	$ 4,356
Underground Secondary Reliability Program	$ 71,296	$ 73,137	$ 77,804
Grounding Transformers	$ 2,519	$ 2,519	$ 2,519
Shunt reactors	$ 2,727	$ 2,752	$ 2,761
Network Reliability	$ 18,909	$ 25,206	$ 25,723
House Isolation Transformers	$ 1,760	$ 240	$ -
Telecom	$ 2,013	$ 1,176	$ 1,176
Transformer Purchase	$ 66,063	$ 66,063	$ 66,063
Sub-Total	$ 527,356	$ 521,805	$ 527,714
Distribution Substation Modernization			
Trip Coil Monitor	$ 235	$ 235	$ 235
USS Automation	$ 150	$ 150	$ 150
Facility Improvement Program	$ 725	$ 425	$ -
Tap Changer Position Indicator System	$ 250	$ 250	$ 250
Temperature Gauges	$ 100	$ 100	$ 100
USS Transformer Replacement	$ 600	$ 600	$ 600
4kV USS Switchgear Replacement	$ 2,200	$ 2,200	$ 2,200
USS Life Extension Program	$ 1,000	$ 1,000	$ 425
4 SV Disaster Recovery	$ 300	$ 300	$ -
4 kV Breaker Replacement	$ 730	$ 769	$ 745
Auto Reclose On Bank Breakers	$ 250	$ 250	$ 250
Sub-Total	$ 6,540	$ 6,279	$ 4,955

DESCRIPTION	Rate Case Submission 2008	2009	2010
Public Safety and Environmental	$ 21,539	$ 12,417	$ 12,150
Oil Minders	$ 600	$ 600	$ 600
Vented Manhole Cover	$ 8,000	$ -	$ -
Tank Rupture Mitigation	$ 900	$ -	$ -
Network Transformer Natural Ester (FR3) program	$ 600	$ 600	$ 600
Street Light Isolation Transformers	$ 10,950	$ 10,950	$ 10,950
NWT Failure Analysis - Polytechnic	$ 489	$ 267	$ -
Transformer Gratings Support Bracket Program	$ -	$ -	$ -
Total	$ 21,539	$ 12,417	$ 12,150
Storm Hardening and Response	$ 44,205	$ 46,762	$ 49,083
C Truss Program	$ 1,729	$ 1,746	$ 1,763
Anderson Switch Replacement	$ 100	$ 100	$ 100
Autoloop Reliability	$ 7,974	$ 7,376	$ 7,359
Aerial (Okonite) Cable Replacement	$ 1,760	$ 2,521	$ 2,532
#4,#6 Self Supporting Wire	$ 3,410	$ 3,165	$ 3,169
ESCO Switch Replacement (Kyle)	$ 2,485	$ 2,509	$ 2,333
33 kV Interruptible Switches	$ 160	$ 435	$ 335
3 Phase Gang Switch Replacement	$ 400	$ 400	$ 400
4 kV Feeder Sectionalizing	$ 450	$ 450	$ 450
13 kV Feeder Sectionalizing	$ 142	$ 135	$ 21
Automated Emergency Ties	$ 750	$ 750	$ 750
Overhead Feeder Reliability	$ 450	$ 750	$ 750
Rear-Lot Pole Elimination	$ 2,437	$ 2,437	$ 2,437
Enhanced 4 kV Grid Monitoring	$ 1,500	$ 2,500	$ 3,500
4 kV Substations - Reliability	$ 111	$ 111	$ 1,774
4 kV UG Reliability	$ 1,268	$ 1,300	$ 1,333
Overhead Secondary Reliability Program	$ 500	$ 500	$ 500
Intelligent OH DAS Autoloop System	$ 2,500	$ 2,500	$ 2,500
4 kV Cable Replacement	$ 4,461	$ 4,461	$ 4,461
Targeted Primary DBC Replacement	$ 800	$ 800	$ 800
URD Cable Rejuvenation/Fault Indicator	$ 608	$ 806	$ 806
Emergency Equipment Management System	$ 600	$ -	-
ATS Installation USS Reliability XW	$ 1,050	$ 2,450	$ 2,450
Transformer Purchase	$ 8,560	$ 8,560	$ 8,560
Total	$ 44,205	$ 46,762	$ 49,083
Advanced Technology	$ 41,150	$ 37,470	$ 34,170
Distribution Simulator	$ -	$ -	$ 2,000
Secondary Visualization Model	$ 5,200	$ 4,000	$ 1,900
Secondary Monitoring (Secondary Model Validation)	$ 10,400	$ 10,200	$ 10,200
System Trouble Analysis and Response (STAR)	$ 500	$ -	$ -
Pole Attachment Project	$ 1,400	$ -	$ -
Grid Optimization (CALM)	$ 1,800	$ 1,800	$ 1,800
Integrated System Model	$ 3,000	$ 2,500	$ 3,000
Decision Aids	$ 1,500	$ 1,500	$ 1,500
Area Profile System	$ 100	$ -	$ -
Joint Pole Use Software	$ 450	$ -	$ -
High Tension Monitoring Data Acquisition System	$ 500	$ 650	$ 500
Meter Shop ADAMS	$ 1,250	$ 1,250	$ -
Integrated Route Sheet (Work Management)	$ 1,000	$ 3,000	$ 3,000
Transformer Asset Mgmt.	$ 1,000	$ 500	$ -
4kV Load Shedding System	$ 150	$ 150	$ 150
ATS Automation	$ 150	$ 150	$ 100
Power Quality (PQNodes) System Upgrade	$ 1,650	$ 1,650	$ 1,650
Rapid Restore - Overhead	$ -	$ -	$ 650
SCADA Systems Consolidation	$ 1,500	$ 800	$ 600
Equipment Analysis Group (IT Initiative)	$ 600	$ 320	$ 120
Electric Distribution Control Center Upgrades	$ 5,000	$ 2,500	$ 500
Mapping System Upgrades	$ 4,000	$ 6,500	$ 6,500
Total	$ 41,150	$ 37,470	$ 34,170
Process Improvement	$ 3,519	$ 16,000	$ 12,500
Work Management Project Tracking	$ -	$ 13,000	$ 10,000
Accounting by Network	$ 350	$ 1,500	$ 1,500
Commercial Service Representative Automation	$ 600	$ 500	$ -
Electric Mobile Dispatch & Extend to Construction	$ 1,700	$ 1,000	$ 1,000
Wireless Support for Electric Operations	$ 869	$ -	$ -
Total	$ 3,519	$ 16,000	$ 12,500
Total Electric Operations	**$ 983,822**	**$ 977,267**	**$ 952,765**

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
SYSTEM & TRANSMISSION OPERATIONS O&M PROGRAMS

		$000s				
		Rate Case Submission				
Title	Category	Actual 2006	Forecast RYE 2009	Forecast RYE 2010	Forecast RYE 2011	Forecast Total
AECC equipment support and maintenance	Advanced Technology		400	400	400	1,200
NERC and EMS Training	Advanced Technology	95	150	150	150	450
New EMS system license maintenance	Advanced Technology		700	700	700	2,100
Telecommunications costs	Advanced Technology	3,800	5,100	5,100	5,100	15,300
Transmission Planning Studies	Advanced Technology	18	118	118	118	354
Training for Emergency CIG	Enhanced Customer Service		100	100	100	300
Manhole Inspections	Environmental	370	950	950	950	2,850
Manhole Refurbishment Program	Environmental	834	1,200	1,200	1,200	3,600
PFT Patrols - New Environmental Program	Environmental		600	600	600	1,800
Conductor Repairs	Improve Reliability	95	450	450	450	1,350
ECC facility maintenance costs	Improve Reliability	1,917	2,100	2,100	2,100	6,300
Install Bird Discouragers on Selected Portions of P & F Line	Improve Reliability		270	270		540
Medium Pressure Manhole Refurbishment	Improve Reliability	53	150	150	150	450
Overhead Line Inspections	Improve Reliability	137	278	278	278	834
Roadway Access	Improve Reliability	65	150	150	150	450
Tower Painting	Improve Reliability		140	140	140	420
Tower Repairs - Lights and Other	Improve Reliability	240	390	440	390	1,220
Transmission reliability - industry group fees	Improve Reliability	85	160	160	160	480
Tree Trimming	Improve Reliability	1,923	2,004	2,004	2,004	6,012
Emergency Drills	Improve Storm Response	24	75	75	75	225
Improve Overhead Transmission Restoration Capability	Improve Storm Response		700	700	500	1,900
New Position - Meterologist (Weather Expert)	Improve Storm Response		150	150	150	450
1 Additional HR for NYISO functions	Process Improvement		100	100	100	300
Conductor Cart Training - New Program	Process Improvement		75	75	75	225
Live Line Maintenance Procedures - New Program	Process Improvement		175	175	175	525
Training Specialist for TLM Training Programs	Process Improvement		125	125	125	375
Update Plan and Profile Drawings - New Program	Process Improvement		50	50	50	150
Furnace Brook Lake Dam Maintenance	Public Safety	4	75	75	75	225
New Position - Scheduling District Operator (DO)	Support Economic Growth		100	100	100	300

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
ELECTRIC OPERATIONS O&M PROGRAMS

PROGRAM DESCRIPTION	2006 Actual	Forecast RYE 2009	Forecast RYE 2010	Forecast RYE 2011	Forecast Total
Support Economic Growth					
Customer Focused Service Ruling Program	0	244	244	244	732
Customer Survey - Load Reduction	0	150	150	150	450
SMART Electric Technologies - new program	0	592	1,092	2,092	3,776
DSM Programs	241	425	609	701	1,735
Maintenance associated with capital work (Energy Services)	0	275	275	275	825
Total Support Economic Growth Programs	241	1,686	2,370	3,462	7,518
Improve Reliability					
Unit Substation repairs and Inspection	300	2,325	1,297	1,214	4,836
Automatic Transfer Switch Operator Replacement	0	900	900	160	1,960
Maintenance of Remote Monitoring System	522	1,956	1,956	1,956	5,868
Maintenance associated with capital work (Network Reliability)	2,272	5,488	6,288	6,938	18,714
Total Improve Reliability Programs	3,094	10,669	10,441	10,268	31,378
Public Safety and Environmental					
Dissolved Gas in Oil Analysis (DGOA)	3,020	3,725	3,810	3,847	11,382
5 Year OH Inspection Program	0	5,443	5,661	5,887	16,991
5-Year UG Structure Inspection Program	11,100	35,001	25,641	25,641	86,283
Annual Stray Voltage Testing Program	6,800	12,522	13,023	13,544	39,089
Electric Distribution Inspection System (EDIS) Improvements	0	30	30	30	90
Mobile Stray Voltage Testing - Sarnoff devices	3,453	10,883	11,286	11,705	33,874
Network Transformer vault cleaning program	0	5,488	6,208	6,208	17,904
Flush Facility Operations Resource Requirements	152	228	228	228	684
Central Quality Assurance	0	315	315	315	945
Total Public Safety and Environmental Programs	24,525	73,635	66,202	67,405	207,242
Storm Hardening and Response					
Customer Response Program	0	418	418	418	1,254
Danger Tree Removal	0	632	632	632	1,896
3-Phase Gang Switch Inspection and Repair program	0	101	101	101	303
Line Clearance Program	5,760	13,755	13,755	13,755	41,265
Overhead Planning Group	0	131	131	131	393
Double Wood program	889	5,235	5,235	3,510	13,980
Emergency Equipment Management System	0	100	100	100	300
Greenburgh Tree Law - additional line clearance	0	6,100	6,100	6,100	18,300
Maintenance associated with capital work (Emergency Response)	0	100	100	100	300
Maintenance associated with capital work (Non-network Reliability)	1,295	6,377	6,398	6,360	19,135
Total Storm Hardening and Response Programs	7,944	32,949	32,970	31,207	97,126
Process Improvement					
Technical Support/NYC Regulatory Liaison Program	300	376	376	376	1,128
Field Auditing & Quality Control Program	300	563	563	563	1,689
NAICS Code Append	0	50	50	50	150
Establishment of a Regional Contractor Oversight / Review Group	0	126	126	126	378
Electric Operations Process Management - EOPM	0	800	800	800	2,400
Engineering Contractor -Vendor Layouts	419	497	575	653	1,725
Electric Operations Project Management	7,641	7,834	8,027	8,027	23,888
Work management system	0	1,000	1,500	1,500	4,000
Electric Distribution Equipment Reconditioning & Repairs	811	1,018	1,018	1,018	3,054
Maintenance associated with capital work (Engineering & other services)	0	713	713	713	2,139
Total Process Improvement Programs	9,471	12,977	13,748	13,826	40,551
Total O&M	45,275	131,916	125,731	126,168	383,815

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
SYSTEM AND TRANSMISSION OPERATIONS CAPITAL PROJECTS
SYSTEM OPERATION CAPITAL PROGRAMS

	($000s)		
	Rate Case Submission		
DESCRIPTION	2008 Update	2009 Update	2010 Update
Energy Management Systems	$ 8,200	$ 2,000	$ -
Work Management Systems	$ 700	$ 550	$ 250
EMS Continuance	$ -	$ -	$ 500
Operation Requirements (On-Line Systems)	$ 2,000	$ 2,400	$ 2,650
District Operations Improvement	$ 900	$ 1,000	$ 1,800
Bulk Power Improvements	$ -	$ 500	$ 500
Facilities / Utilities Improvements	$ 3,100	$ 4,850	$ 1,850
TOTAL SYSTEM OPERATION	$ 14,900	$ 11,300	$ 7,550

SPARE TRANSFORMER PROBABILITY ANALYSIS - Summer 2007

N = Number of Units in service
F = Failure rate (Historical)
R = Replacement Time (years)
S = Number of Spares
K = Exact Number of Failures
MTBF = Mean Time Between Failures

$$\text{Probability} = \sum_{K=0}^{S} \left((N \times F \times R)^{K} \times e^{-(N \times F \times R)}\right)/K!$$

Failure rates were determined for each particular type of equipment by using the number of failures since 1980 & the service years.

The method of analysis is a Poisson Probability Distribution. This was used to determine the appropriate number of spares to achieve a 90% Confidence Level that a spare will be available when a failure occurs.

Delivery Lead Ttime was taken into account to determine the order point for units. For transformers where the MTBF was low and the delivery time is long, it was determined that the units would have to be pre-ordered to maintain our desired spare level.

	MVA	Volt. Class	Historical Failure Rate	MTBF Years	Number in Service	Time to Replace	Resulting Confidence Levels: with 1 Spare in Inventory	with 2 Spares in Inventory	with 3 Spares in Inventory	with 4 Spares in Inventory	with 5 Spares in Inventory	REMARKS
Transformers		500/345			3	2.5						Single Phase Units. Installed Spare
"		345/230/13	0.03704	27.0	1	2.5	99					
"	327	345/138/138	0.00741	13.5	10	2.5	98					
"	234	345/138/13.8	0.0194	2.2	23	2.5	69	90	98			Includes Academy units
"	327	345/138	0.00617	27.0	6	2.5	99					
	420	345/138	0.00823	9.3	13	2.5	97					Includes Mott Haven
"	234	345/69	0		1	2.5	99					Used 1% failure rate
"	65	345/13	0		2	2.5	99					Used 1% failure rate
"	130	138/69	0.01365	3.9	19	2.5	86	97				
"	93	138/13/13	0.00823	13.5	9	2	99					
"	93	138/33/27	0.00417	3.7	65	2	89	98				Includes Newtown
"	65	138/13	0.00884	0.8	149	2	26	51	73	87	95	Includes Mott Haven/Parkview/ Rockview/Astor/Cherry/Woodrow
	41.7	138/13	0		6	2	99					Used 1% failure rate
"	46	69/13	0.00347	9.0	32	2	99					
"	58	69/13	0.00884	10.3	11	2	98					Used 65 MVA Failure Rate
"	16	138/27	0		4	2	99					Used 1% failure rate
PARs		345	0.01681	11.9	5	2.5	98					Goethals PAR one failure
"		138	0.01852	3.9	14	2.5	86	97				Includes Academy units
"		69	0		4	2.5	99					Used 1% failure rate
Shunt Reactor	150	345	0.01634	5.1	12	2.5	91	99				

Company Name: Con Edison
Case Description: Electric Rate Filing
Case: 07-E-0523

Response to DPS Interrogatories – Set Staff19
Date of Response: 08/08/2007
Responding Witness: IIP

Question No. :351
Subject: Public Safety and Environment Follow-up to IR DPS-148. For the Environmental Risk Program: - 1. Provide an itemized breakdown (beyond what is provided in the work papers) of how the funding listed for each year was derived. 2. Provide the work schedule for this program. 3. Provide a copy of the SSO Risk Management Team risk assessment done that identified substations that have a potential for serious environmental impact from dielectric fluid. 4. What was the driving force for doing this risk assessment? 5. What is the specification for the oil/water separator systems and drain modifications?

Response:

1-2 The following table is a list of current candidate projects to be funded under the Environmental Risk Program. This list is updated on a frequent basis as project requests are received, reviewed, and prioritized. Project costs are rough estimates based on the present scope of work. More refined estimates are created during the design phase of the project. The projects listed below have been assigned a projected year for start of construction based on current project status and priority.

In addition to the projects listed, other candidate projects are considered for inclusion in this program as they are identified by the risk assessment process.

3. See attached excel spreadsheet.

4. Risk Management is a key component of the company's Environmental and Safety Management Systems and the company's EH&S policy. Identifying and reducing EH&S risk potential is also one of the five EH&S key objectives. The company's approach to risk management is focused on analyzing, managing, and to the greatest degree possible, eliminating potential risks to the environment and the health and safety of employees and the public.

5. Oil/water separator systems and drain modifications are custom designed for each project based on the unique attributes and requirements of the intended location. An oil/water separator (OWS) is used in substations to act as secondary containment for oil filled equipment and to process storm water that falls over oil filled equipment. In the case of an emergency release of oil from electrical equipment with deluge activation, the OWS processes the large amount of deluge water and oil, sending the water to the sewer and holding the oil. Without an oil/water separator in an emergency, oil would be spread around the facility by the deluge system water. This creates a large environmental cleanup and a good potential for off-site environmental contamination. In the case where the deluge does not go off, but there is a large amount of oil spilled from electrical equipment connected to an OWS, the OWS minimizes the cleanup, since the oil is directed to the OWS for collection. In cases where there is a large oil spill that is directed to the OWS, the oil holding compartment of the unit is pumped out as part of the site cleanup. When an OWS is installed, site drainage modification is required to

STATION	DESCRIPTION	EST. COST($)	YEAR
MILLWOOD	Containment moats for Transformers 1, 2, and TA1 and oil containing circuit breakers.	$2,300,000	2008
E75TH ST.	Provide measures to prevent hazards to a nearby school in the event of a catastrophic failure of transformer or bushing.	$550,000	2008
W49TH ST.	Replace oil/water separator	$750,000	2008
E63RD ST.	Install concrete moats for transformer vaults #3 and #13 with portable oil/water separator	$ 2,000,000	2009
LEONARD STREET	Transformer #14 wall	$ 750,000	2009
E179TH ST.	SPCC containment and walls	$ 1,000,000	2009
RAMAPO	1500 Transformers units 1-4 containment moats	$2,500,000	2010
FRESH KILLS	PAR #2 and Transformer #21W containment moats	$1,000,000	2010

ensure that all equipment and facility areas that are covered by the OWS appropriately drains to the unit.

Company Name: Con Edison
Case Description: Electric Rate Filing
Case: 07-E-0523

Response to DPS Interrogatories – Set Staff25
Date of Response:
Responding Witness:

<u>Question No. :</u> 422
Subject: Public Safety & Environment For the Pumping Plant Improvement Program: - 1. Provide an itemized breakdown (beyond what is provided in the work papers) of how the funding listed for each year was derived. 2. Since this is classified as an on-going program, what are the future plans related to this program? 3. What upgrades were made as a result of the DEC Consent order? 4. What was the associated cost of this DEC Consent order on an annual basis that should be broken down in the same manner as part 1 of this question where applicable?

RESPONSE

1. **Provide an itemized breakdown (beyond what is provided in the work papers) of how the funding listed for each year was derived.**

Pumping Plant Improvements cost breakdown:

The Pumping Plant Improvement Program consists of a combination of pumping and cooling plant improvement initiatives. The average annual cost of this program for 2008 – 2010 can be summarized as follows:

Program description	Average annual cost
Pumping plant improvements (3 plants/year @ $1,500,000/ea.	$4,500,000
PURS automation (1.5 feeders/year @ $1,000,000/feeder)	$1,500,000
Leak Detection system upgrades	$1,100,000
Cooling plant upgrades (2 plants/year @ $200,000/ea.)	$400,000
Pump house connectivity	$800,000
Alarm panel upgrade	$200,000
Total	**$8,500,000**

2. Since this is classified as an on-going program, what are the future plans related to this program?

Shown below is the Pumping Plant Improvement Program candidate project list for 2008 – 2010.

Pumping Plant Improvement Program		
Corona #1		Replace plant
49th St #1		Replace skid
49th St #2		Replace skid
Hudson Avenue #5		Replace skid
Hudson Ave #6		Replace skid
13th St #1		Replace skid
13th St #2		Replace skid
Rainey #1		Replace skid
Astoria West #7 and #8		Replace both with one new plant
Queensbridge #1 and #2		Replace both with one new skid
Harrison #1		Replace skid
Sprainbrook #2		Replace skid
Dunwoodie #2		Replace skid
75th St #1		Replace skid
East River #1		Retire and install backpressure assembly as a replacement
Greenwood #2		Replace skid
Elmsford #1		Explore possibility of incorporating into station upgrade project
Millwood #1		Replace skid
Washington Street #1		Replace skid
Jamaica #1		Retire or Upgrade - TBD
Vernon 1-6 and 8		Replace skid
Glendale #1		Replace skid

3. What upgrades were made as a result of the DEC Consent order?

There were 26 pumping plant replacements as a result of the DEC consent order. These are listed in the following table:

DEC consent order list						
Manhattan	**Description**			**Queens**	**Description**	
Avenue A	Skid	PP #1		Jamaica	Skid	PP #3
Avenue A	Skid	PP #2		Jamaica	Skid	PP #4
W19 ST.	Skid	PP #1		Jamaica	Skid	PP #6
W19 ST.	Skid	PP #2		North Queens	Skid	PP #4
Cherry St	Skid	PP #1		North Queens	Skid	PP #7
E29 St	Skid	PP #1		Astoria West	New Plant	PP #14
E29 St	Skid	PP #2		Rainey	Skid	# 1
E13 St	New Plant	PP #3				
W 110 St	Skid	PP #1		**Bronx**		
				Sherman Creek	Skid	PP #1
Brooklyn				Hellgate	Skid	#1
Hudson Ave East	Skid	PP #1		E179 St	New Plant	PP #1
Greenwood	Skid	PP #1				
Farragut	Skid	#3		**Westchester**		
Farragut	Skid	#4		Dunwoodie	Skid	#1
Farragut	Skid	#6				
Staten Island						
Fresh Kills	Skid	PP #1				

4. What was the associated cost of this DEC Consent order on an annual basis that should be broken down in the same manner as part 1 of this question where applicable?

The following data is the total expenditures and the affected locations for the Pumping Plant Improvement Program for the years 2002 – 2006. There were DEC replacements made prior to 2002.

2002 **Total: $ 2,761,000**

DEC: $ 1,720,000
Non DEC: $ 1,041,000

Locations:
Ave A PH1
Ave A PH2
Trade Center PH1
W19th St PH1
W19th St PH2

2003 **Total: $ 3,424,000**

DEC: $ 2,737,000
Non DEC: $ 687,000

Locations:
Cherry St PH1
E13th St PH3
E29th St PH3
E29th St PH2
Hudson Ave East PH1
Hudson Ave East PH2

2004 **Total: $3,049,000**

DEC: $ 2,641,000
Non DEC: $ 408,000
Locations
Astoria West PH14
Jamaica PH3
Jamaica PH4
Jamaica PH6
North Queens PH4
North Queens PH7
White Plains PH2

2005 **Total: $7,424,000**

DEC: $ 3,591,000
Non DEC: $ 3,833,000

Locations
Dunwoodie PH1
Fresh Kills PH1
Greenwood PH1
Sherman Creek PH1
W110th St PH1

2006 **Total: $ 7,136,000**

DEC: $ 3,284,000
Non DEC: $ 3,852,000

Locations
Rainey PH4
E179th St PH1
Farragut PH2
Farragut PH3
Hell Gate PH1

Company Name: Con Edison
Case Description: Electric Rate Filing
Case: 07-E-0523

Response to DPS Interrogatories – Set Staff25
Date of Response: 08/17/2007
Responding Witness: IIP

Question No. :423
Witness: Infrastructure Investment Panel Subject: Public Safety & Environment For the PURS Control & Data Acquisition Program: 1. Provide an itemized breakdown (beyond what is provided in the work papers) of how the funding listed for each year was derived. 2. Provide the work schedule from the beginning to the completion date. 3. How does work under the Pumping Plant Improvement affect this project?

Response:

1.
The following cost estimates were used to derive the required funding for 2008 – 2010:

2008
M51 upgrade:
Contractor B/G Electric Work: $300,000
Contractor A/G Electric Work: $200,000
CCTN Work: $350,000
Company Labor: $150,000

2009
M52 upgrade:
Contractor B/G Electric Work: $250,000
Contractor A/G Electric Work: $250,000
CCTN Work: $350,000
Company Labor: $150,000

2010
Completion of M51/M52 project:
Contractor B/G Electric Work: $160,000
Contractor A/G Electric Work: $165,000
CCTN Work: $350,000
Company Labor: $75,000

The remaining $2.25M for PURS feeders in 2010 has not yet been estimated. The feeders to be worked are:

- Q35L and Q35M
- 45 and 46
- 61, 62, and 63
- M54 and M55

CCTN: Corporate Communications Transmission Network

2. Equipment Procurement -- 10/06 through 12/07
Engineering & Design – 12/06 through 12/07
Contracts Procurement -- 11/07 through 9/08
Construction – 2/08 through 3/09

3. The Pumping Plant Improvement has no effect on this project.

Company Name: Con Edison
Case Description: Electric Rate Filing
Case: 07-E-0523

Response to DPS Interrogatories – Set Staff7
Date of Response: 07/17/2007
Responding Witness: IIP

Question No. :125
Is the Substation Structures Upkeep Program a new program? If not, explain why this program is now being implemented compared to previous years. Additionally, provide the following information associated with each of the five specific programs covered under the substation structures upkeep programs identified within the Company's testimony, during each of the past five years. a) Forecasted budget b) Actual amount spent c) Description of work completed including dates and locations

Response:

See attached.

DPS-125
Substation Structures Upkeep Program

Response:
The Substation Structures Upkeep Program is not a new program. The Company objects to the timeframe requested. Below are the forecasted preliminary budgets, actual amounts spent, and the work performed related to the program from 2004 to 2006.

2004

Forecasted budget:	$0
Actual amount spent:	$383,000
Work performed:	Replacement of high voltage test sets at various locations

2005

Forecasted budget:	$1,000,000
Actual amount spent:	$1,244,000
Work Performed:	
Astoria	Transformer yard improvements
E13th St	Battery room/office
Sedgwick	Workout location upgrade

2006

Forecasted budget:	$0
Actual amount spent:	$1,018,000
Work Performed:	
Various	Metal enclosures on diesel generators
Buchanan	Drainage piping
Astoria	Yard expansion
Sedgwick	Workout location upgrade
Hellgate	Upgrade lighting
Sherman Creek	Upgrade lighting
Willowbrook	Spare breaker
Cherry St.	Security fence
Woodrow	Spare breaker

Company Name: Con Edison
Case Description: Electric Rate Filing
Case: 07-E-0523

Response to DPS Interrogatories – Set Staff8
Date of Response: 07/17/2007
Responding Witness: IIP

Question No. :145
Subject: Miscellaneous Programs For the projects/programs listed, provide: 1. A detailed description and justification for why the project/program is needed to meet the company's system miscellaneous programs. 2. A ranking of all projects/programs in priority of importance order. 3. Cash flow requirements for all projects/programs from inception through completion. 4. Backup details and explanation of how the cost figures were derived.

Capital:

A. Area Substation Reliability (IIP-2 page 2 of 4)
B. Facility Upgrade (IIP-2 page 3 of 4)
C. High Voltage Test Sets (IIP-2 page 3 of 4)
D. Small Capital (IIP-2 page 3 of 4)

Response:

See attached.

<u>**Question No. :145-A**</u>

Area Substation Reliability

1. A detailed description and justification for why the project/program is needed to meet the company's system miscellaneous programs.

As a result of the 1990 Seaport incident, a recommendation was made to provide two means of local high side clearing through the installation of a circuit switcher and interrupter with primary supply feeders for each area substation transformer bank. If the vault is space constrained, audiotone transfer trip relay scheme can be installed instead. This design would provide two independent means of high-side clearing with separate and independent relay protection systems for protracted low side faults.

This program also includes the retirement of the Automatic Ground Switch (AGS), which used to provide the provide protection for the low side faults. The AGS system is an antiquated system no longer supported by its manufacturer, its components are obsolete, and its insulating medium is SF6 gas. The AGS retirement program has been combined with this reliability program and where feasible the work will be done simultaneously.

A single-mode failure philosophy was developed to prevent extensive damage and station shutdown from sustained 13kv faults. The philosophy includes the addition of an independent line of protracted fault protection, installation of a 138 kV transformer circuit switcher and interrupter, the provision for control cable system route separation, separate DC supply systems, switchgear compartmentalization, and improved fire rated design. The design philosophy has changed since some older substations were designed and constructed. Upgrading existing area substations to meet present design philosophy will reduce the possibility of loss of the area substation during a protracted fault incident. Also, as part of this program we will look to retire the AGS where feasible.

2. A ranking of all projects/programs in priority of importance order.

The following projects are in progress as part of this program:

- E29th St
- E36th St
- Cherry St
- Brownsville

3. Cash flow requirements for all projects/programs from inception through completion.

This program is not cash-flowed at the project level. The cash flow for this program is projected at $8,500,000 per year.

4. Backup details and explanation of how the cost figures were derived.

Backup details and explanation of cost figures can be found in the workpapers previously submitted.

Question No. : 145-B

Facility Upgrade

1. **A detailed description and justification for why the project/program is needed to meet the company's system miscellaneous programs.**

This program is required to fund larger scale projects not covered by other capital programs. These projects are necessary to improve and maintain substation facilities. Also, discontinuing use of temporary office facilities will support continued efficient deployment of personnel and will provide employees a safe and professional work environment. This program is necessary to correct and upgrade numerous age related structural and facility issues in order to ensure safe and reliable operation of the substations. Also, continued use of temporary office facilities is not a viable long term option.

2. **A ranking of all projects/programs in priority of importance order.**

The following table is a list of current candidate projects to be funded under the facility upgrade program. This list is updated on a frequent basis as project requests are received, reviewed, and prioritized. Each project listed below has been assigned a priority of a high (H), medium (M) or low (L).

In addition to the projects listed, there are a number of other candidate projects being considered for inclusion in this program that do not yet have fully developed job scopes and estimates, have not been prioritized, and are therefore not included in the list presented. These projects fall into the categories of drainage, foundation, and wall improvements, HVAC and lighting upgrades.

STATION	DESCRIPTION	EST. COST($)	PRIORITY
BENSONHURST 2 & WATER ST.	Add heat to switchgear rooms	$575,000.00 $ 575,000.00	H
PARKCHESTER #1	Install a new high voltage test set facilities	$ 500,000.00	H
E63RD ST.	Resolve drainage issues for transformer vaults #3 and #13	$ 2,000,000.00	H
E75TH ST.	Provide measures to prevent hazards to a nearby school in the event of a catastrophic failure of transformer or bushing.	$ 550,000.00	H
PLYMOUTH STREET	Replace obsolete fire protection system	$ 650,000.00	H
DUNWOODIE	Replace F.P. water supply and deteriorated deluge house	$ 1,500,000.00	H
PARKCHESTER #1	Re-grade substation to eliminate need for breaker lifts.	$ 500,000.00	M
HELLGATE 52 STORE ROOM	Renovate Hellgate office facility to provide additional space.	$ 500,000.00	M
WORLD TRADE CENTER	WTC Transformer Vault #1 exit.	$ 500,000.00	M
E29TH ST.	Installation of moat systems in Transformer Vaults #1 and #2.	$ 2,000,000.00	M

W65TH ST.	W65TH Street Substation & ECC- New HVAC.	$ 500,000.00	M
STATION	**DESCRIPTION**	**EST. COST($)**	**PRIORITY**
SPRAIN BROOK	Expansion of control house.	$ 995,741.00	M
BRIARCLIFF WORKOUT	Modify second floor for additional storage and office space.	$ 690,000.00	L
1823 SEDGEWICK AVE.	Sedgewick - Office Area Finish.	$ 500,000.00	L
DUNWOODIE	Convert retired 4kV gallery to office space.	$ 2,000,000.00	L

3. Cash flow requirements for all projects/programs from inception through completion.

The estimated project costs are provided above. Since the work performed under this program is relatively small in nature, cash flow requirements are not developed at the project level.

4. Backup details and explanation of how the cost figures were derived.

The estimated project costs provided are based on the best information available which depends on the current status of each project. Projects in the early stages have order of magnitude estimates while projects farther along will have more detailed Engineering estimates.

Question No. :145-C

High Voltage Test Sets

1. A detailed description and justification for why the project/program is needed to meet the company's system miscellaneous programs.

There are 100 fixed and 7 mobile high voltage DC test sets in Substation Operations that are used for distribution feeder processing. Various test sets are over 20 years old and require constant repair. This program will purchase and replace 3 DC test sets per year and is needed in order to provide a minimum of two (2) feeder processing DC test sets per distribution station and to systematically replace existing test sets based on age, corrective maintenance and availability of parts. The replacement program will target the worst performing test sets for replacement.

There are currently 3 mobile A/C VLF (0.1 HZ) test sets for distribution feeder processing on the Con Edison System (one per operating region in Manhattan, Brooklyn/Queens, Westchester/Bronx). Under this program, we will increase the number of mobile sets with the purchase of an additional 3 mobile A/C VLF (0.1 HZ) test sets. We will also purchase and install 3 fixed A/C VLF station test sets per year to expand the number of A/C hi-pots performed on distribution feeders. This program is to support conducting A/C hi-pot testing on EPR and Poly cable.

This program will also fund the purchase of 2 new 345 KV transmission voltage A/C test sets. These units will replace those currently at the W49th St. and Dunwoodie stations. The W49th St. test set is no longer supported by the manufacturer and is approximately 30 years old. This set is used to perform conditioning and proof tests of the indoor equipment after overhauls and repairs and is no longer reliable. Dunwoodie station no longer has an A/C test set. It is no longer functioning and has reached the end of its useful life and cannot be repaired. Replacement of these units will eliminate the need to rent units when required which is not preferred due to cost and vendor availability constraints.

2. A ranking of all projects/programs in priority of importance order.

The DC test sets will be replaced based on age, reliability, and availability of parts. The replacements currently planned for the following years in order of priority are listed below:

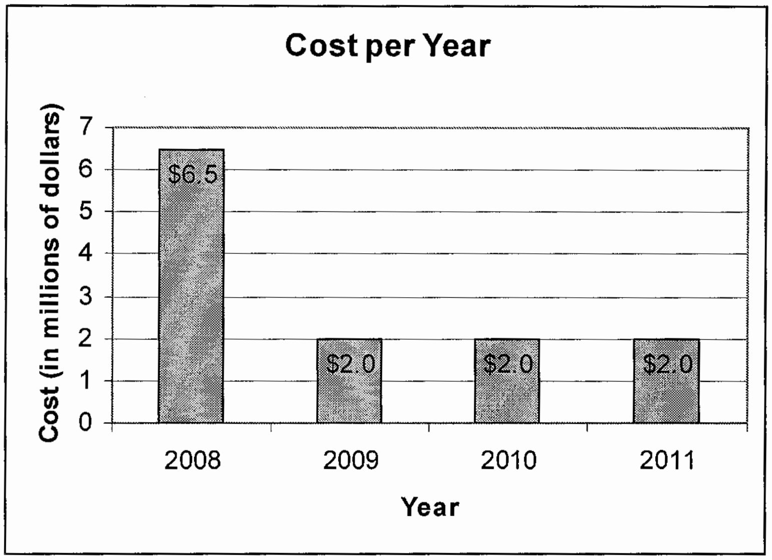
1. Parkchester
2. Bensonhurst BK8
3. Bensonhurst BK9
4. Granite Hill W4
5. Plymouth St. (install second test set)
6. E 179th St. (install second test set)
7. Bruckner (install second test set)
8. Corona Q8

The AC test sets will first be installed at 27 KV stations such as Corona, Bensonhurst, Brownsville, Greenwood, and Jamaica. This program will be expanded in the future to include 13KV stations.

3. Cash flow requirements for all projects/programs from inception through completion.

Cost Breakdown:

Description \ Year	2008	2009	2010	2011
3 A/C Test Sets per Yr.	$1.5 M	$1.5 M	$1.5 M	$1.5 M
3 Mobile A/C Test Sets	$1.5 M			
2 New 345kV A/C Tests	$3 M			
3 D/C Test Sets per Yr.	$0.5 M	$0.5 M	$0.5 M	$0.5 M
Total	**$6.5 M**	**$2.0 M**	**$2.0 M**	**$2.0 M**



5. Backup details and explanation of how the cost figures were derived.

Cost figures are based on actual expenditures from previous installations and equipment purchases.

Question No. : 145-D

Small Capital

1. **A detailed description and justification for why the project/program is needed to meet the company's system miscellaneous programs.**

   This program is required to fund small scoped projects that are not covered by other capital programs. These projects are necessary to improve and maintain the infrastructure of substation facilities.

2. **A ranking of all projects/programs in priority of importance order.**

   The following table is a list of current candidate projects to be funded under the small capital program. This list is updated on a frequent basis as project requests are received, reviewed, and prioritized. Each project listed below has been assigned a priority of a high (H), medium (M) or low (L).

   In addition to the projects listed, there are a number of other candidate projects being considered for inclusion in this program that do not yet have fully developed job scopes and estimates, have not been prioritized, and are therefore not included in the list presented. These projects fall into the categories of fire detection, paving and fencing, bird netting, lighting, flooring, and HVAC improvements.

STATION	DESCRIPTION	EST COST($)	PRIORITY
QUEENSBRIDGE	Replace obsolete fire detection system.	$ 213,627	H
VERNON	Replace obsolete fire detection system.	$ 250,000	H
GREENWOOD	Replace potential transformers - Bus Sections 1, 2, & 5.	$ 47,000	H
HELLGATE E179TH ST TREMONT PARKCHESTER	Replace Barksdale low pressure switches on feeders.	$ 285,304	H
GREENWOOD	Replace low and high pressure alarm system for feeders 42231, 42232, 23161, 23162, 38B14.	$ 56,265	H
BROWNSVILLE	Replace low and high pressure alarm system on FDRS 38B01, 38B02, 38B03, 38B04 & 38B05.	$ 61,012	H
WEST 65TH STREET	Replace Barksdale switches.	$ 492,000	H
ASTORIA WEST SUBSTATION	Replacement of fire detection system.	$ 200,000	H
FARRAGUT	Update fire pump power supply.	$ 150,000	H
ASTORIA WEST SUBSTATION	Relocate diesel generator fuel tank to comply with FDNY regulations	$ 150,000	H
147TH STREET PURS	147th Street PURS plant wall repairs	$ 263,000	H
CORONA SUBSTATION	Upgrade deteriorated deluge houses.	$ 475,000	H
MILLWOOD SUBSTATION	Footing for lightning arrestor on Bus Section 1W (C Phase) is starting to lean, causing arrestor and bus connection to arrestor to lean.	$ 400,000	H

STATION	DESCRIPTION	EST COST($)	PRIORITY
W65TH ST	Replace Fire Protection water supply	$ 300,000	H
EAST RIVER	Back pressure assembly cabinet	$ 90,000	M
MILLWOOD	Stabilize Disconnect Switch 1W	$ 120,000	M
GREENWOOD	Replace potential transformers - BUS SECTION #4	$ 16,000	M
GREENWOOD	Replace potential transformers - BUS SECTION #3	$ 16,000	M
FARRAGUT	Replace 138KV PT for Transformer #7	$ 45,000	M
DUNWOODIE	Battery room bldg.	$ 235,890	M
QUEENSBRIDGE	Install roof over L & P Transformer	$ 75,000	M
VERNON SUBSTATION	Vernon Substation Control Room HVAC	$ 125,000	M
WATER ST SUBSTATION	Design and install a more secure louver system for all exterior walls at the transformer vaults at Water St. S/S.	$ 100,000	M
RAINEY	Install a mast and antenna to provide wireless communication between Ravenswood Tunnel Head House and Corporate LAN system.	$ 90,000	M
HARRISON SUBSTATION	Install roof gratings on transformer vaults	$ 250,000	M
GREENBURG SERVICE CENTER	Upgrade Storm Water Drainage System	$450,000	M
E179TH ST	Install new water service and new water pump in the station.	$350,000	M
EAST RIVER	Improve drainage system	$300,000	M
WEST110TH ST	Improve drainage in transformer vault #4	$125,000	M
HELL GATE	HVAC for conference room.	$75,000	L
WEST 19TH ST	Exhaust fans in pump rooms.	$184,549	L
HELL GATE	HVAC Improvements.	$76,493	L
LEONARD ST	HVAC Improvements.	$75,000	L
EAST 179TH ST	HVAC Improvements.	$150,000	L
EAST 63RD ST	Replace HVAC system.	$284,318	L
RAINEY	Seal moat floor of Pumphouse # 6.	$125,000	L
EASTVIEW	Modify roadway to prevent water accumulation.	$336,000 Ret. $51,000	L

3. Cash flow requirements for all projects/programs from inception through completion.

The estimated project costs are provided above. Since the work performed under this program is relatively small in nature, cash flow requirements are not developed at the project level.

4. Backup details and explanation of how the cost figures were derived.

The estimated project costs provided are based on the best information available which depends on the scope and current status of each project. Projects in the early stages have order of magnitude estimates while projects farther along may have more detailed Engineering estimates.

Company Name: Con Edison
Case Description: Electric Rate Filing
Case: 07-E-0523

Response to DPS Interrogatories – Set Staff32
Date of Response: 08/28/2007
Responding Witness:

Question No. :489
Subject: System Reliability – In-depth Cost Breakdowns - Provide a more in-depth cost breakdown of how the future expenditures proposed by the Company in the exhibits and work papers were derived for the following programs: - SOCCS RTU Replacement ($3M for 2008, $11M total) - Substation Loss Contingency ($2M for 2008, $8M total) - Area Reliability ($8.5M for 2008, $34M total) - Facility Improvements ($6M for 2008, $24M total) - Structural Integrity/Station Betterment ($2M for RYE 2009, $6M total)

Response:

See attached (including attached confidential document). Please note that some of the costs figures included the question associated are not be reflective of the Company's filing.

The following information is being provided in response to a request for a cost breakdown of the cash flow requirements for the Structural Integrity/Station Betterment program. Concrete pads and footings, trough covers, substation walls and equipment protective coatings will be addressed as part of this on-going program. Required funding to support this program is $2 million per year. This program proactively addresses long term facility and equipment degradation caused by exposure to the elements as well as normal wear over time. This restoration work is considered O&M and is beyond the scope included in the base O&M budget.

Painting:

Feeder Towers
Scope: Work requires lead competent trained personnel and plasticizing around tower base to catch lead chips. Scope includes scraping of existing peeling paint, grinding and removal of any rust, application of a primer coat and then the finish coat. An 80 foot or 150 foot man lift is required depending on the reach. Feeder outages are required.

List of towers to be painted
Millwood -10 towers
Buchanan - 7 towers
Eastview - 8 towers
Total: 25 towers

Estimated cost:
Total cost/ tower = $25,000
25 x $25,000 = $625,000

East 13th St. Flight Deck
Scope: Paint structural steel and cable trays. Requires extensive scaffold erection, removal of paint and rust, containment for lead contamination, and equipment outages.

Estimated cost:
Cable trays = $135,000
Steel: Estimate in progress, expected to exceed $500,000

Station Painting
Scope: The following stations have been identified as requiring structural steel painting and/or paint removal.
Farragut
Greenwood
Gowanus
Plymouth St.

Hudson Ave East
Sherman Creek
Hellgate
Bruckner
E179th St
Fox Hills
Fresh Kills
North Queens
Astoria East/West
Rainey
Queensbridge
Dunwoodie

Estimated cost: The required work to access (scaffolding or lifts), remove peeling paint, prepare steel, and paint in each of these stations is substantial. Detailed cost estimates have not yet been fully developed.

Transformers

Scope: The transformers require lead abatement which includes encapsulation, HEPA tools, and qualified workers. The units must then be primed, and finish painted. The radiators must be painted using the dipped method. The main tank top surface must be painted with a non-skid, slip resistant paint.

1 - Pleasantville Spare
2 - Astoria Item #1 - 420 MVA Spare
3 - Rainey Tr-7W
4 - Astoria Item #2 - 327 MVA Spare
5 - Ramapo 1500 -1
6 - Astoria Item #11 58 MVA Spare
Estimated cost
Estimated cost per transformer: $40,000 - $50,000
Total cost: $240,000 - $300,000 for 6 transformers

Concrete Footings/ Walls:

Breaker pad restoration:

Millwood	7 pads	$950,000
Sprainbrook	7 pads	$500,000
Pleasant Valley	3 pads	$225,000
Dunwoodie	2 pads	$50,000
Ramapo	2 pads	$85,000

Additional concrete repair has been identified at the following stations:

Brownsville
Gowanus
Vernon
North Queens
E179th St
Hellgate
Sherman Creek
Dunwoodie
E29th St
E36th St
W42nd St
Webster Ave

Estimated cost: The extent of necessary repairs at each station varies. This work includes breaker, switchgear, and relay house foundation repairs, structural steel foundation repairs, and building and retaining wall refurbishment. Detailed cost estimates have not yet been developed.

Trough Covers

Scope: Replace degradation trough covers and perform repairs to trough walls as necessary.

The following stations require cable trough cover replacement and repairs:

Fresh Kills	$100,000
Fox Hills	$50,000
Goethals	$50,000
Sherman Creek	$65,000
Millwood	$100,000
Sprain Brook	$100,000
Eastview	$100,000
Dunwoodie	$75,000
Ramapo	$75,000
Farragut	$100,000
Greenwood	$50,000
Gowanus	$50,000
Hudson Ave East	$50,000
Rainey	$75,000
Astoria East	$50,000

This information is being provided in response to a request for a cost breakdown of the Facility Upgrade Program cash flow. The following table is a list of current candidate projects to be funded under the Facility Upgrade program.

STATION	DESCRIPTION	EST. COST($)
BENSONHURST 2	Add Heat to Switchgear Rooms.	$575,000
WATER ST.	Add Heat to Switchgear Rooms.	$ 575,000
PARKCHESTER #1	Building modifications to accommodate installation of new high voltage test set.	$ 500,000
PLYMOUTH ST.	Replace obsolete fire protection system.	$ 650,000
DUNWOODIE	Replace Fire Protection system water supply and deteriorated deluge house.	$ 1,500,000
ALL STATIONS	Technical support needed to perform NFPA required full flow test at substations. Items needed: 1) Pump curves 2) Equipment and Procedures 3) Training	$ 2,000,000
FRESH KILLS	Replace Fire Detection System. Existing system is inoperable.	$ 500,000
RAINEY	Install upgraded and centralized Fire Protection system for the Rainey transformers and reactors.	$ 1,000,000
HARRISON	Create a security package: 1) Install station perimeter fencing 2) Secure driveway gate with cameras and additional lighting in order to deter individuals from trespassing.	$ 750,000

STATION	DESCRIPTION	EST. COST($)
DUNWOODIE-GRANITE HILL	The Siamese connection for the Granite Hill S/S deluge system failed recent hydrostatic tests. The line needs to be replaced to meet the NFPA standards and to protect the transformers. In addition, the existing North Fire Pump House is obsolete and needs to be increased in size and fire-proofed. The pump house is located adjacent to Transformer G5 and has no fire protection. Solution: -Replace all underground fire system supply lines to the transformer deluge systems fed from the North Fire Pump House. -Increase the size of the fire pump house and pad. -Provide 3-hour fire rating protection for the pump house from exposure to Transformer G-5.	$ 1,500,000
PARKCHESTER #1	Re-grade substation to eliminate the need for breaker lifts.	$ 500,000
HELLGATE 52 STORE ROOM	Renovate Hellgate office facility to provide additional space.	$ 500,000
WORLD TRADE CENTER	WTC Transformer vault #1 exit. The only current valid exit from this vault that meets OSHA and NYC code requirements is through Transformer vault #2. Should an incident occur in Transformer vault #2, this exit path would not be available.	$ 500,000
E29TH ST.	Installation of moat systems in Transformer vaults #1 and #2. Deluge system activation in these vaults results in water intrusion to adjacent property owner's basement.	$ 2,000,000
W65TH ST.	W65th St. Substation & ECC- New HVAC.	$ 500,000
SPRAIN BROOK	Expansion of control house.	$ 1,000,000
MILLWOOD	Roof replacements for relay houses 1,2,3, and 4. Roofing on the relay houses has deteriorated, with corrosion, deformation, and water intrusion. This will prevent inadvertent trips.	$ 1,600,000
59^{TH} STREET	Pier 98 Cable Cooling System Clog (Modify salt water pump intake chambers to mechanically eliminate silt accumulation in cable cooling heat exchangers.)	$ 500,000
DUNWOODIE	Existing retaining walls are in poor condition and disrepair. Replace existing retaining walls and provide proper drainage.	$ 500,000
ALL STATIONS	Provide oil/water separator systems for potential leakage to waterways.	$ 3,860,000
FRESH KILLS	The current Fresh Kills rain run-off drainage pit located in the 345KV yard is not sufficient to handle the rain run-off during a heavy rain storm. During heavy rains the trough and relay houses flood with rain water. This flooding can result in equipment failure and outages which affect our system reliability. Install an adequate run-off solution to accommodate heavy rainfall in the 345KV yard.	$ 750,000
WASHINGTON ST.	Eliminate storm water run-off from station onto adjoining property.	$ 750,000

STATION	DESCRIPTION	EST. COST($)
EAST 63RD ST.	Remove both temporary trailers and build permanent offices for SSM/ECB and PST working groups.	$ 600,000
PLYMOUTH ST.	Expand existing high voltage test room to accommodate a second high voltage test set, or build a stand alone indoor facility to house the test set.	$ 500,000
BRIARCLIFF R.C.	Modify second floor for additional storage and office space.	$ 690,000
SEDGWICK AVE.	Sedgwick – refurbish office area	$ 500,000
DUNWOODIE	Convert retired 4kV gallery to office space.	$ 2,000,000
DUNWOODIE	The existing retention pond liner is lifting in numerous areas due to flow under the liner. In addition, the Yonkers storm water system is not capable of handling the amount of site run-off. The potential exists for discharge to bypass the oil water separator system and flow directly into the Yonkers system. It is proposed to construct a new concrete retention pond with an impermeable liner with adequate capacity to detain sufficient run-off to prevent bypass of the oil water separator system.	$ 4,100,000
VARIOUS PURS SITES	At various PURS sites, backup power in the form of emergency diesel generators is brought to the site during the North Queens outage. Currently, it takes hours to secure the electrical connections to the buss. If the buss is still alive, I&A has to be brought in to make the live connections. ASM is looking for a quick connect solution to temporarily connect a diesel to a buss.	$ 800,000
LEONARD ST.	Install a central air unit to cool control room and computer room.	$ 575,000

This following information is being provided in response to a request for a cost breakdown of the SOCCS RTU Replacement project.

The project estimate is provided below:

SOCCS RTU Replacement

EQUIPMENT	
RTU	$3,804,000
Conduit/cable/fiber	$78,000
CONSTRUCTION CONTRACT	$585,000
COMPANY LABOR	
Inspection	$72,000
Test – PST	$608,000
ECB	$440,000
Operations	$334,000
OVERHEADS AND CONTINGENCY	$3,078,000
TOTAL	$9,000,000

SUBSTATION RELIABILITY PROGRAM

PURCHASED EQUIPMENT	
Circuit Switchers/GIS	$ 3,000,000.00
DTT Equipment	$ 500,000.00
Miscellaneous	$ 500,000.00
Sales Taxes	$ 400,000.00
	$ 4,400,000.00
CONSTRUCTION CONTRACT	
Civil Contract	$ 5,000,000.00
COMPANY LABOR	
Inspection/Proj Mgt	$ 500,000.00
Test - PST	$ 1,500,000.00
Operations	$ 600,000.00
ECB	$ 3,500,000.00
Construction Services	$ 2,000,000.00
	$ 8,100,000.00
Total Direct Cost	$ 17,500,000.00
OVERHEADS AND CONTINGENCY	$ 8,000,000.00
Total (2008-2010)	**$ 25,500,000.00**

Substation Loss Contingency

This project is geared toward preparing for the loss of any one of a number of selected transmission substations. Planning and procurement of spare equipment in advance of a substation loss will enable more rapid restoration of the electric system. To date, restoration plans have been developed for the individual loss of one of several 345 kV, 138 kV, or 69 kV transmission substations. These plans will be used to develop engineering specifications for procurement of selected spare transmission and substation equipment.

2008

Item	**Description**	**Total Estimated Cost ($000)**
Portable Relay Protection Houses	Self contained on trailers, including batteries, diesel generator, rectifier	1700
Portable Relay Protection House - Accessories Box	Termination Points	40
Relay Isolation Devices	Flexitest Switches	20
12 conductor #12 wire	1,000 ft reels	25
Single/multimode Fiber Optic Cable	1,000 ft reels	15
Communication Cable/Devices	1,000 ft cable reels & other devices	10
Portable Alarm Panels	Self contained alarm panels on wheels	190
Total		***2000***

2009

Item	**Description**	**Total Estimated Cost ($000)**
Engineering Labor	Wiring Packages/Marked Prints for identified restoration scenarios	1600
Construction/Testing - Connections to S/S	Connections from Portable Relay House to Eastview & Gowanus S/S for periodic testing	20
Portable Pumping Plant	To provide a means for pressurizing pipe type underground transmission feeders	380
Total		***2000***

2010

Item	**Description**	**Total Estimated Cost ($000)**
Split Core Current Transformers	(6) 345kV & (6) 138kV to accommodate 8" & 10" riser pipe	170
Transition Joints	For solid dielectric to pressurized oil type cable joints	1300
Engineering Labor	Procedures/Specifications	200
CCPD	(6) 345kV & (6)138kV	330
Total		***2000***

Company Name: Con Edison
Case Description: Electric Rate Filing
Case: 07-E-0523

Response to DPS Interrogatories – Set Staff25
Date of Response: 08/17/2007
Responding Witness: IIP

Question No. :424
Subject: Public Safety & Environment For the Security Enhancements: 1. Provide an itemized breakdown (beyond what is provided in the work papers) of how the funding listed for each year was derived. ~~2. Provide a copy of CE-ES-2002~~.* 3. Provide a detail work schedule.

Response:

Please see attached spreadsheet for itemized breakdown and schedule. ~~A copy of CE-ES-2002 is also attached.~~

* Deleted for purposes of Exhibit __ (IIP-13).

Location	Description	2008	2009	2010
Harrison	Install Security System Consisting Of CCTV, Access And Monitoring System	300		
Cedar	Install Security System Consisting Of CCTV, Access And Monitoring System	300		
Ossining	Install Security System Consisting Of CCTV, Access And Monitoring System	300		
McLean PURS	Install Security System Consisting Of CCTV, Access And Monitoring System	200		
Corona	Upgrade Security System Consisting Of CCTV, Access And Monitoring System	1,200		
Gowanus	Upgrade Security System Consisting Of CCTV, Access And Monitoring System	1,200		
Fox Hills	Install Security System Consisting Of CCTV, Access And Monitoring System		300	
Willowbrook	Install Security System Consisting Of CCTV, Access And Monitoring System		300	
Brook Ave PURS	Install Security System Consisting Of CCTV, Access And Monitoring System		250	
147th St PURS	Install Security System Consisting Of CCTV, Access And Monitoring System		250	
North Transition	Install Security System Consisting Of CCTV, Access And Monitoring System		250	
Jamaica	Upgrade Security System Consisting Of CCTV, Access And Monitoring System		900	
Ramapo	Upgrade Security System Consisting Of CCTV, Access And Monitoring System		1,300	
Woodrow	Install Security System Consisting Of CCTV, Access And Monitoring System			300
Wainwright	Install Security System Consisting Of CCTV, Access And Monitoring System			300
W123nd PURS	Install Security System Consisting Of CCTV, Access And Monitoring System			250
Bay St PURS	Install Security System Consisting Of CCTV, Access And Monitoring System			250
Queens Bridge	Upgrade Security System Consisting Of CCTV, Access And Monitoring System			900
W42nd St	Upgrade Security System Consisting Of CCTV, Access And Monitoring System			1,200
Bensonhurst	Upgrade Security System Consisting Of CCTV, Access And Monitoring System			250
Man down radios	10 stations/year at $55,000/ea	550	550	550
Water St louvers		50		
		4100	**4100**	**4000**